TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

EXECUTIVE SUMMARY

INTRODUCTION

The goal of this injection project is to demonstrate the potential of the Mt. Simon Sandstone, a major regional saline-water bearing reservoir in the Illinois Basin (Basin), to be a significant carbon dioxide (CO_2) geologic sequestration formation. The proposed site is on the property of the Archer Daniels Midland (ADM) Company in Decatur, Illinois, and the proposed source of the CO_2 is ADM's ethanol fermentation operation at their Decatur facility. The Mt. Simon is the deepest sedimentary rock that overlies the Precambrian-age basement granites of the Illinois Basin and is considered a major regional saline-water bearing reservoir in the Illinois Basin. An average injection rate of 1,000 metric tonnes per day (t/day) of nearly pure CO_2 is anticipated for a three-year period followed by a post-injection monitoring period. The total mass injected is expected to be 1.0 million metric tonnes (Mt).

While the research project has a defined duration, after the research project is completed there may be interest to continue injection into this well for the entire period of the injection permit and potentially via permit extensions beyond the initial permit period. Additionally, the research scope may change at a later time (before or during the 3 year injection period), and up to 1,100 t/day of CO_2 may be available for injection.

The Midwest Geologic Sequestration Consortium (MGSC), led by the Illinois State Geologic Survey (ISGS), is one of seven U.S. Department of Energy (U.S. DOE) funded partnerships that are studying regional geologic variations that impact geologic storage. This project is considered a large-scale injection demonstration project.

The key research targets for the this large-scale injection test relate to CO_2 injectivity and volumetric storage capacity and efficiency of the saline reservoir, the integrity of the seals to contain the CO_2 in the subsurface, and the entire process of pre-injection characterization, injection process monitoring, and post-injection monitoring to understand the fate of the CO_2.

The proposed sequestration site at the ADM facility will be supplied with 99+ percent pure CO_2 from the ethanol production part of ADM's operations. The CO_2 is wet at atmospheric pressure from the fermentation vessels, so it is dehydrated and compressed to between 1,400 and 2,000 psi. The dehydration/compression facility was developed near the north boundary of the ADM facility; the CO_2 is transported about 6,400 ft through a 6-inch pipe to the injection well, CCS#1. The injection well is located on an ADM-owned, 150-acre tract that adjoins the facility.

Injection Plan

The proposed mass to be injected is nominally 1,000 t/day of supercritical CO_2 with a cumulative mass of 1.0 Mt over three years. The CO_2 will be supplied by ADM from an ethanol fermentation plant at their Decatur, Illinois agricultural products processing facility. Injection rates will be metered and may be suspended from time to time to understand pressure fall-off in the reservoir or for other reservoir testing. It is expected that injection may cumulatively cease as much as 1 month per year.

The injection interval was identified based on well logs, core samples, and drill stem tests from the initial well drilled on the site. A single injection well with 9 5/8 inch diameter long-string casing and 4.5-inch diameter tubing is adequate to meet the 1,000 t/per day injection rate.

During the period prior to injection, intense assessment of perforation strategies and subsequent modeling to predict the behavior of the CO_2 plume based on the well data took place. Permeability-thickness product and injectivity of several sub-intervals within the Mt. Simon was calculated and assessed to fully understand the impact of lower permeability intervals within the Mt. Simon on the distribution of the buoyant CO_2 plume. Based on the injection well and on Champaign and Fayette County Mt. Simon wells, at least one lower reservoir quality interval within the Mt. Simon was found above the injection interval.

Supplemental Monitoring

Although extensive supplemental injection zone, caprock, and out-of-zone monitoring will be completed, a groundwater monitoring program is included. Initial site environmental monitoring was designed to obtain a baseline for environmental parameters for at least one year before CO_2 injection. This monitoring benefits from MGSC and ISGS experience at the small-scale enhanced oil recovery (EOR) pilots at which reservoir fluids, groundwater, gases in the vadose zone, and wellbore gas were sampled and analyzed.

A pre-CO_2 injection geologic baseline was established with geophysical well logs, a 3D seismic survey, and fluid sampling. Geophysical monitoring techniques include permanently placing geophones in the injection well that facilitate microseismic monitoring. DOE-funded monitoring will continue during injection (three years) and post-injection (three years).

Downhole fluid samples were taken to determine composition of the brine, which was important to assess mineral trapping and dissolution of CO_2 into the brine. Drill stem and pressure falloff tests were used to estimate flow characteristics. Post-injection seismic imagery will provide an improved understanding of the geologic structure. The extensive suite of data collected in and around the injection well through core analyses and petrophysical tests, borehole tests, well logging and seismic profiling was analyzed and used to build geologic models of the entire stratigraphic column from the Mt. Simon to the surface. Reservoir flow modeling will be used to history match the injection performance and predict the distribution of the CO_2 plume.

1 GENERAL INFORMATION

This permit application presents the information needed to start the permitting process for obtaining a UIC Class VI permit for geologic sequestration. The permit describes general information about the operator, ADM (Section 1). It also details the site geology (Section 2), well construction (Section 3), operations and surface equipment (Section 4), modeling (Section 4), injection stream properties (Section 5), and modeling (Section 6). This application also provides the plans required for the project. The plans are: The Area of Review and Corrective Action Plan (Section 6), The Monitoring Plan (Section 7), The Well Plugging Plan (Section 8), The Post-Injection Site Care Plan (Section 9),and The Emergency and Remedial Response and Contingency Plans (Section 10). Section 11 provides a statement on how Financial Responsibility will be handled.

This document contains the information required by Federal regulations (40 CFR Part 146, Subpart H) for underground injection of carbon dioxide for geologic sequestration (Class VI injection wells). It provides general information required for all UIC permits (40 CFR 144.31(e)(1)-(6). Table 1-1 provides a cross-reference to demonstrate that the Federal regulation requirements of 40 CFR 146 Subpart H are met within the format of this UIC permit application.

Required USEPA Forms 7520-6 (Underground Injection Control Permit Application) and 7520-14 (Plugging and Abandonment Plan) are provided at the end of this section. A 7520-14 form is provided for both the proposed injection well and verification well.

1.1 INFORMATION REQUIRED FOR ALL UNDERGROUND INJECTION CONTROL PERMITS

Applicant Information:

Applicant:	Archer Daniels Midland Company – Corn Processing	
	USEPA Identification No.	ILD984791459
	IEPA Identification No.	1150155136
Facility Contact:	Mr. Dean Frommelt, Division Environmental Manager	
Mailing Address:	4666 Faries Parkway	
	Decatur, IL 62526	
Phone:	217-451-6330	

Site Information:

County:	Macon
SIC Codes:	2046 – wet corn milling
	2869 – industrial organic chemicals, ethanol
	2075 – soybean oil mills
	2076 – vegetable oil mills

Owner/Operator:	Archer Daniels Midland Company – Corn Processing 4666 Faries Parkway Decatur, IL 62526
Operator Status:	Private
Phone:	1-800-637-5843
Indian Lands:	The site is not located on Indian lands.

1.2 EXISTING ENVIRONMENTAL PERMITS

NPDES	Industrial Storm Water Permit IL0061425
UIC	ADM-UIC-012
RCRA	None
Other	Various air permits, including Title V Clean Air Act Permit (#1711500005)
Other	Sanitary District of Decatur Pre-Treatment, Permit #200

1.3 NATURE OF BUSINESS

Archer Daniels Midland Company (ADM) is the world leader in BioEnergy and has a premier position in the agricultural processing value chain. ADM is one of the world's largest processors of soybeans, corn, wheat, and cocoa. ADM is a leading manufacturer of biodiesel, ethanol, soybean oil and meal, corn sweeteners, flour, and other value-added food and feed ingredients. Headquartered in Decatur, Illinois, ADM has over 29,000 employees, more than 240 processing plants, and net sales for the fiscal year ending June 30, 2010 of $62 billion. Additional information can be found on ADM's Web site at http://www.admworld.com.

1-1 Table Cross-Reference Table

Cross-Reference Table to Class VI Injection Well Rules (40 CFR Part 146, Subpart H—Criteria and Standards Applicable to Class VI Wells)

Class VI Well Regulatory Requirements	Application Section Where Addressed
Sec. 146.82 Required Class VI permit information. (a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following:	
(1) Information required in § 144.31(e)(1) through (6) of this chapter;	Section 1
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is	Fig. 2-35 Fig. 6-2 Appendix I

Class VI Well Regulatory Requirements	**Application Section Where Addressed**
required to be included on this map;	
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including: (i) Maps and cross sections of the area of review; (ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment; (iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions; (iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s); (v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and (vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Section 2 Figures. 2-2 to 2-7 Section. 2.4 Section 2.2.2 Section. 2.4 Section 2.4
(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the Director may require;	Section 6.4 Appendix L
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Sec. 2.5.2 Fig. 2-22 to 33
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Sections 2.2.3, 2.5.2, Figs. 2-22 to 2-34
(7) Proposed operating data for the proposed geologic sequestration site: (i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream; (ii) Average and maximum injection pressure; (iii) The source(s) of the carbon dioxide stream; and (iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Section 4 Section 4 Section 5 Section 5
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	NA Sections 2.2 and 2.3
(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	Section 3.1.6
(10) Proposed procedure to outline steps necessary to conduct injection operation;	Section 4
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	Figure 4-2 and 4-3
(12) Injection well construction procedures that meet the requirements of § 146.86;	NA
(13) Proposed area of review and corrective action plan that meets the requirements under § 146.84;	Section 6.5
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	Section 11
(15) Proposed testing and monitoring plan required by § 146.90;	Section 7
(16) Proposed injection well plugging plan required by § 146.92(b);	Section 8
(17) Proposed post-injection site care and site closure plan required by § 146.93(a);	Section 9
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	Section 9.1.3
(19) Proposed emergency and remedial response plan required by § 146.94(a);	Section 10

Class VI Well Regulatory Requirements	**Application Section Where Addressed**
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	Section 10.1.4
(21) Any other information requested by the Director.	Agency action
(b) The Director shall notify, in writing, any States, Tribes, or Territories identified to be within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.	Agency action
(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information: (1) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section; (2) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section; (3) Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well; (4) The results of the formation testing program required at paragraph (a)(8) of this section; (5) Final injection well construction procedures that meet the requirements of § 146.86; (6) The status of corrective action on wells in the area of review; (7) All available logging and testing program data on the well required by § 146.87; (8) A demonstration of mechanical integrity pursuant to § 146.89; (9) Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and (10) Any other information requested by the Director.	Agency action
(d) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.	Not applicable
§ 146.83 Minimum criteria for siting. (a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises: (1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream; (2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	 Section 2
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	Agency action
§ 146.84 Area of review and corrective action. (a) The area of review is the region surrounding the geologic sequestration project where USDWs	 Sections 6.2 and

Class VI Well Regulatory Requirements	Application Section Where Addressed
may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	6.3
(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	Section 6.5
(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sections 6.1.1 and 6.1.2
(2) A description of: (i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review; (ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section. (iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	Section 6.5
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action: (1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must: (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project; (ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and (iii) Consider potential migration through faults, fractures, and artificial penetrations. (iv)	Section 6.3
(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the Director may require; and	Section 6.4
(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	Section 6.5.3
(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	Section 6.5.3

Class VI Well Regulatory Requirements	Application Section Where Addressed
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must: (1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section; (2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section; (3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and (4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Section 6.5
(f) The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	Sections 10 and 11
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Section 6.5
§ 146.85 Financial responsibility. (a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions: … (b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit. … (c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response. … (d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure. … (e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, as required by § 146.84, if the Director determines during the annual evaluation of the qualifying financial instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94). (f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	Section 11 Agency action
§ 146.86 Injection well construction requirements. (a) *General.* The owner or operator must ensure that all Class VI wells are constructed and completed to: (1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones; (2) Permit the use of appropriate testing devices and workover tools; and (3) Permit continuous monitoring of the annulus space between the injection tbg and long string casing.	Section 3
(b) *Casing and Cementing of Class VI Wells.* (1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between	Section 3.1.2, and Section, Section 2,

Class VI Well Regulatory Requirements	Application Section Where Addressed
USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information: (i) Depth to the injection zone(s); (ii) Injection pressure, external pressure, internal pressure, and axial loading; (iii) Hole size; (iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material); (v) Corrosiveness of the carbon dioxide stream and formation fluids; (vi) Down-hole temperatures; (vii) Lithology of injection and confining zone(s); (viii) Type or grade of cement and cement additives; and (ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.	
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Section 3.1.2
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	Section 3.1.2
(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind wellbore.	Section 3.1.2
(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Section 3.1.2 Section 3.1.3 Appendix J
(c) *Tubing and packer.* (1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	 Section 3.1.2 Section 3.1.3
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Section 3.1.2
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information: (i) Depth of setting; (ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids; (iii) Maximum proposed injection pressure; (iv) Maximum proposed annular pressure; (v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream; (vi) Size of tubing and casing; and (vii) Tubing tensile, burst, and collapse strengths.	 Section 3.1.2 Section 5 Section 4.1.7 Section 3.1.2 Section 3.1.2 Section 3.1.2
§ 146.87 Logging, sampling, and testing prior to injection well operation. (a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Section 3.1.5

Class VI Well Regulatory Requirements	Application Section Where Addressed
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and (2) Before and upon installation of the surface casing: (i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and (ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented. (3) Before and upon installation of the long string casing: (i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and (ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented. (4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include: (i) A pressure test with liquid or gas; (ii) A tracer survey such as oxygen-activation logging; (iii) A temperature or noise log; (iv) A casing inspection log; and (5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	Section 3.1.6 Agency action
(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	Section 2.2.2
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Section 2.2.2
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s): (1) Fracture pressure; (2) Other physical and chemical characteristics of the injection and confining zone(s); and (3) Physical and chemical characteristics of the formation fluids in the injection zone(s).	Section 2.2.2
(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s): (1) A pressure fall-off test; and, (2) A pump test; or (3) Injectivity tests.	Section 3.1.6
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	NA
§ 146.88 Injection well operating requirements. (a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and	Section 3.1.6

Class VI Well Regulatory Requirements	Application Section Where Addressed
incorporated into the permit.	
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Section 3.1.2
(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Section 3.1.2
(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	Section 3.1.2 Section 4.1.8
(e) The owner or operator must install and use: (1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and (2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (*e.g.*, automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and (3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	 Section 3.1.2 Section 3.1.4 Not applicable
(f) If a shutdown (*i.e.*, down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must: (1) Immediately cease injection; (2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone; (3) Notify the Director within 24 hours; (4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and (5) Notify the Director when injection can be expected to resume.	Section 10
§ 146.89 Mechanical integrity. (a) A Class VI well has mechanical integrity if: (1) There is no significant leak in the casing, tubing, or packer; and (2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	 Section 3.1.6
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Section 3.1.5 and 3.1.6
(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section: (1) An approved tracer survey such as an oxygen-activation log; or (2) A temperature or noise log.	Section 7.1.5
(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	Agency action
(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the	Agency action

Class VI Well Regulatory Requirements	**Application Section Where Addressed**
Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	
(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	Agency Action
(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	Agency action
§ 146.90 Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	 Section 7
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 7.1.1
(b) Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Section 7.1.2
(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by: (1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or (2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or (3) Using an alternative method approved by the Director;	Section 7.1.4
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including: (1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and (2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	Section 7.2 and 7.3
(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	Section 7.1.5
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by	Section 7.1.5

Class VI Well Regulatory Requirements	Application Section Where Addressed
the Director based on site-specific information;	
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (*e.g.*, the pressure front) by using: (1) Direct methods in the injection zone(s); and, (2) Indirect methods (*e.g.*, seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Section 7.2.2 Section 9.1.1
(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW. (1) Design of Class VI surface air and/ or soil gas monitoring must be based on potential risks to USDWs within the area of review; (2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter; (3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 *et seq.*) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;	
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	Agency action
(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows: (1) Within one year of an area of review reevaluation; (2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or (3) When required by the Director.	Section 7.4
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.	Section 7.6
§ 146.91 Reporting requirements. The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well: (a) Semi-annual reports containing: (1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data; (2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure; (3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit; (4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken; (5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period	 Section 7.5

Class VI Well Regulatory Requirements	Application Section Where Addressed
and the volume injected cumulatively over the life of the project; (6) Monthly annulus fluid volume added; and (7) The results of monitoring prescribed under § 146.90.	
(b) Report, within 30 days, the results of: (1) Periodic tests of mechanical integrity; (2) Any well workover; and, (3) Any other test of the injection well conducted by the permittee if required by the Director.	Section 7.5
(c) Report, within 24 hours: (1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW; (2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs; (3) Any triggering of a shut-off system (*i.e.*, down-hole or at the surface); (4) Any failure to maintain mechanical integrity; or. (5) Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	Section 7.5
(d) Owners or operators must notify the Director in writing 30 days in advance of: (1) Any planned well workover; (2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and (3) Any other planned test of the injection well conducted by the permittee.	Section 7.5
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	Section 7.5
(f) Records shall be retained by the owner or operator as follows: (1) All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure. (2) Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period. (3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected. (4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure. (5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	Section 7.5
§ 146.92 Injection well plugging. (a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Section 8.1
(b) *Well plugging plan.* The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information: (1) Appropriate tests or measures for determining bottomhole reservoir pressure; (2) Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89; (3) The type and number of plugs to be used; (4) The placement of each plug, including the elevation of the top and bottom of each plug;	Section 8.1

Class VI Well Regulatory Requirements	Application Section Where Addressed
(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and (6) The method of placement of the plugs.	
(c) *Notice of intent to plug.* The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Section 8.1
(d) *Plugging report.* Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	Section 8.1
§ 146.93 Post-injection site care and site closure. (a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. (1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	Section 9 Section 9
(2) The post-injection site care and site closure plan must include the following information: (i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s); (ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1); (iii) A description of post-injection monitoring location, methods, and proposed frequency; (iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and, (v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	Section 9.1.3 Section 6.3 Section 9.1.3 Section 9.1.2 Section 9.1.3
(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.	Section 9.1.1 Section 9.1.2
(4) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	As noted
(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered. (1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and	Section 9.1.2 Section 9.1.4

Class VI Well Regulatory Requirements	Application Section Where Addressed
approved by the Director. (2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs. (3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs. (4) If the demonstration in paragraph (b)(3) of this section cannot be made (*i.e.*, additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	Section 9.1.3 Section 9.1.3 Section 9.1.3
(c) *Demonstration of alternative post-injection site care timeframe.* At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe. (1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of: (i) The results of computational modeling performed pursuant to delineation of the area of review under § 146.84; (ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures; (iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration; (iii) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site; (iv) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase; (v) The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section; (vi) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement; (vii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure; (viii) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review; (ix) The distance between the injection zone and the nearest USDWs above and/ or below the	Section 9.1.3

Class VI Well Regulatory Requirements	Application Section Where Addressed
injection zone; and (x) Any additional site-specific factors required by the Director. (2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria: (i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards; (ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available; (iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project; (iii) Predictive models must be calibrated using existing information (*e.g.*, at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available; (iv) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements; (v) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration. (vi) An approved quality assurance and quality control plan must address all aspects of the demonstration; and, (vii) Any additional criteria required by the Director. (viii)	
(d) *Notice of intent for site closure.* The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	Section 9.1.4
(e) After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	Section 9.1.4
(f) The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include: (1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; (2) Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and (3) Records reflecting the nature, composition, and volume of the carbon dioxide stream.	Section 9.1.4
(g) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information: (1) The fact that land has been used to sequester carbon dioxide; (2) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and (3) The volume of fluid injected, the injection zone or zones into which it was injected, and the	Section 9.1.4

Class VI Well Regulatory Requirements	Application Section Where Addressed
period over which injection occurred.	
(h) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	Section 9.1.4
§ 146.94 Emergency and remedial response. (a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 10
(b) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must: (1) Immediately cease injection; (2) Take all steps reasonably necessary to identify and characterize any release; (3) Notify the Director within 24 hours; and (4) Implement the emergency and remedial response plan approved by the Director.	Section 10
(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	Agency action
(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows: (1) Within one year of an area of review reevaluation; (2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or (3) When required by the Director.	Section 10

2. GEOLOGY AND HYDROGEOLOGY OF THE SITE

2.1 ELEVATION OF LAND SURFACE AT WELL LOCATION.

The surface elevation at the proposed carbon sequestration site is approximately 674 feet above mean sea level (MSL), as referenced from the Forsyth, Illinois, United States Geological Survey (USGS) 7.5-minute topographic quadrangle map. Two vertical cross-sections and a map of the proposed injection site are shown in Figures 2-5 through 2-7. Based on interpretation of 3D seismic data collected at the site, two cross-sections were developed showing the bedrock stratigraphy at the proposed well site. Line A-A’ is a west to east cross-section, while Line B-B’ is a south to north cross-section. The cross-sections provide elevations on the y axis and have no vertical exaggeration.

Excluding the injection and the verification wells, no other deep wells penetrate the Eminence, Ironton-Galesville, Eau Claire or Mt. Simon formations (Figure 2-8) within the area of review (AOR), Section 6. The deeper horizons were projected from regional maps and well locations not displayed on the cross-sections (Figures 2-6 and 2-7).

2.2 INJECTION ZONE.

The injection zone is the Cambrian-age Mt. Simon Sandstone. Carbon dioxide (CO_2) injected through the well will be contained in the injection zone and will flow into the Mt. Simon at the injection interval. The injection interval is a portion of the Mt. Simon where the injection well is perforated**.** This section describes the regional extent and deposition in Section 2.2.1 and the site specific data in Section 2.2.2

2.2.1 *Regional Injection Zone Information*

GENERAL INFORMATION

The thickest and most widespread saline-water-bearing reservoir (saline reservoir) in the Illinois Basin is the Mt. Simon Sandstone (Figure 2-8). It is overlain by the Cambrian Eau Claire formation, a regionally extensive very low-permeability unit. The Mt Simon is underlain by Precambrian granitic basement. There are 21 wells recorded in central and southern Illinois that were drilled into the Mt. Simon (to depths greater than 4,500 feet). Many of the wells penetrate less than a few hundred feet into the Mt. Simon. In addition, most wells are too old to have an associated suite of modern geophysical logs suitable for petrophysical analysis. Although comprehensive reservoir data for the Mt. Simon are lacking, there are sufficient data to demonstrate its regional presence. In the northern half of Illinois, the Mt. Simon is used extensively for natural gas storage and detailed reservoir data are available from these projects. Ten Mt. Simon gas storage projects show that the upper 200 feet has porosity and permeability high enough to be a good sequestration target. Excluding the injection and verification wells, the closest Mt. Simon penetration to the ADM site is about 17 miles southeast in Moultrie County, the Sanders Harrison #1 (Harrison #1). Only the top two hundred feet of the Mt. Simon was drilled. Based on logs from the injection and verification wells, the Mt. Simon thickness at the site is about 1,500 feet.

Sample descriptions from the Harrison #1 well indicate that there is good porosity in the top 200 feet of the Mt. Simon. The nearest well with a porosity log for the entire thickness of the Mt. Simon is the the Humble Oil Weaber-Horn #1 well (Weaber-Horn #1). It was drilled on the Loudon Field anticline in Fayette County, a major oilfield 51 miles south of the ADM site. The Weaber-Horn #1 drilled through 1,300 feet of Mt. Simon before drilling into the Precambrian granite. The top of the Mt. Simon at the Weaber-Horn #1 well was at 7,000 feet and, based on calculations from wireline logs, the sandstone formation's gross thickness had an average porosity of about 12 percent. The Weaber-Horn #1 well log porosity data are similar to those found in deeper wells at the Manlove gas storage field (Manlove Field) in Champaign County, approximately 37 miles northeast of the ADM site. The Manlove Field is the deepest Mt. Simon gas storage field in the Illinois Basin and provides part of the basis for regional characterization of the deep Mt. Simon. The permeability and porosity at the ADM site (Section 2.2.2) are also sufficient for geologic sequestration and add another data point to establish that the Mt. Simon is porous and thick throughout the site. A north-south trending cross section A-A' across the Hinton #7 , Harrison #1, CCS #1, and Weaber-Horn #1 wells is provided in Figure 2-9).

DEPOSITION AND LITHOLOGY

The deposition of the Mt. Simon Sandstone has commonly been interpreted to be a shallow, subtidal marine environment. Most of these studies, however, were based on either surface study of the upper part of the Mt. Simon or on study of outcrops in Wisconsin or the Ozark Dome. Based on studies of the samples and logs of the CCS #1 well, the upper part of the Mt. Simon is interpreted to have been deposited in a tidally influence system similar to the reservoirs used for natural gas storage in northern Illinois. However, the basal 600 feet of Mt. Simon sandstone is an arkosic sandstone that was originally deposited in a braided river – alluvial fan system. This lower Mt. Simon Sandstone is the principal target reservoir for sequestration because the dissolution of feldspar grains formed abundant amounts of secondary porosity.

The Mt. Simon Sandstone varies regionally in lithology from conglomerates to sandstone to shale. Six dominant lithofacies have been recognized: cobble conglomerate, stratified gravel conglomerate, poorly-sorted sandstone, well-sorted sandstone, interstratified sandstone and shale, and shale (Bowen et al., 2011). Poorly-sorted sandstone lithofacies are most common. Within the Mt. Simon at the site there are discrete intervals of predominantly finer-grained sandstone and coarser-grained sandstone. The basal portions of some of the coarser-grained strata are often conglomeratic. In addition, there is a 40-foot thick arkosic interval at the base of the Mt. Simon. Dark gray shale laminae occur between some of the sandstone strata (Morse and Leetaru, 2005).

The principal cementing material is quartz in the form of overgrowths and feldspar precipitation. Most of the very fine-grained intervals contain large amounts of detrital and authigenic potassium feldspar. The lower part of the Mt. Simon tends to have more feldspar-rich zones than the upper part. These zones consequently tend to have greater feldspar framework grain dissolution and increased porosity. These feldspar-rich intervals appear to have the best reservoir characteristics for sequestration (Bowen et al. 2011).

HYDROGEOLOGY

Groundwater flow in the deeper part of the Illinois Basin is not well studied because few wells penetrate deep formations including the Mt. Simon Sandstone. However, based on limited field data and numerical modeling some information on groundwater flow is available. Within the Mt. Simon Sandstone, Bond (1972) determined that groundwater flows from west to east beneath the northern third of Illinois. Bond also noted that groundwater flows to the south in the deeper part of the Illinois Basin, but some data supporting this conclusion were questionable. Groundwater flow in the Mt. Simon Sandstone is generally very slow, on the order of inches per year. Finally, Bond (1972) noted that groundwater flows upward from the Mt. Simon aquifer to the Ironton-Galesville in the Chicago area, where pumpage has lowered pressures in the Ironton-Galesville. Gupta and Bair (1997) used a steady-state, variable density, groundwater flow model to evaluate flow in the Mt. Simon Sandstone in the Midwest (Ohio, Indiana and parts of Illinois, Wisconsin, Michigan, Pennsylvania, West Virginia and Kentucky), including the eastern portion of the Illinois Basin. Results from this modeling indicated that flow in the shallow layers, such as in the Pennsylvanian bedrock, follows topographic-driving forces – recharge in upland areas and discharge in topographic lows such as river valleys. For deeper layers such as the Mt. Simon Sandstone, the flow patterns are influenced by the geologic structure with flow away from arches such as the Kankakee Arch and toward the deeper parts of the Illinois Basin (Figure 2-16). The model also indicated that groundwater flows upward from the Mt. Simon to the Eau Claire and downward from the Ironton-Galesville into the Eau Claire (Figure 2-17), but these vertical velocities are very small, <0.01 inches per year.

The modeling results of Gupta and Bair agree with results of Cartwright (1970). Cartwright (1970) estimated that 59,000 acre-ft of groundwater discharged from the Illinois Basin bedrock to streams. Cartwright (1970) also argued that 95% of this discharge flowed through vertical fractures in the Wabash valley fault zone and the Duquoin-Louden anticlinal belt. These modeling results also agree with a hypothesis described by Bredehoeft et al. (1963) to explain the high brine concentrations (3 to 6 times higher than present seawater) found in some deep basins including the Illinois Basin. Bredehoeft et al. (1963) argued that confining layers such as the Eau Claire act as semi-permeable membranes, allowing water to pass out of permeable formations such as the Mt. Simon while retarding the passage of charged salt particles. The clay minerals in the confining layer have a net negative charge which retards the anions in the water. These anions then retard the movement of the cations (positive charge) via electrical attraction. This process happens very slowly, over geologic time periods of hundreds of thousands of years.

2.2.2 *Site-Specific Injection Zone Information*

ZONE THICKNESS AND PERFORATED INTERVAL

The Mt. Simon was found at a depth of 5,545 feet to 7,051 feet (Frommelt, 2010) based on borehole logging data for the CCS #1 well. An interval of high porosity and permeability was identified at the base of the Mt. Simon. This basal interval was selected as the initial injection interval for the CCS #1 well and was perforated from 6,982 to 7,050 feet. Based on the data from the CCS #1 well (Frommelt, 2010), the injection zone is a porous and permeable sandstone that, in some intervals, is an arkosic sandstone. Grain size varies from very-fine grained to coarse grained. The sandstones are primarily composed of quartz, but some intervals contain more than 15 percent feldspar. Diagenetic clay minerals are not common.

While CO_2 may be stored in the entire thickness of the Mt Simon, the perforated or injection interval is much smaller (68 ft) in the high porosity zone relatively deep in the Mt. Simon. Injectivity is primarily a product of net formation thickness (*b*) and permeability (*k*) or permeability-thickness (*kb*), while storage volume is primarily a function of net formation thickness and effective porosity. Because of the thickness and permeability of the Mt. Simon noted in the CCS #1 well, Weaber-Horn, and Hinton wells, nominal maximum injection capacity of 1,200 metric tonnes per day (MT/day) is anticipated to be highly probable. CO_2 reservoir flow modeling (see Section 5.4 of this application) shows that the lower zone can readily accept the 1,200 MT/day maximum injection rate.

FRACTURE PRESSURE

A step-rate test (Earlougher, 1977) was conducted in the injection well on September 26, 2009 into the initially perforated interval from 7,025 to 7,050 feet, at the base of the Mt. Simon. The primary purpose of the test was to estimate the fracture pressure of the injection interval. A bottom-hole pressure gauge with surface readout was used. The pressure gauge was located at 6,891 feet inside the tubing, 134 feet above the uppermost perforation. Water with clay-stabilizing potassium chloride was injected in at 2.0 barrel per minute (bpm) increments starting at 2.0 bpm (84 gallons per min, gpm) and stepping up to 8.0 bpm (336 gpm). Each rate was maintained for approximately 45 minutes. The pressure near the end of each injection period was plotted against the injection rate to determine the fracture pressure (Figure 2-10).

In Figure 2-10, the line with the steeper slope, between 2 and 6 bpm, is the perforated interval's response to water injection prior to fracturing. The second line with the less steep slope, between 6 an 8 bpm, is the formation response after the fracture developed. The intersection of the two straight lines is 4,966 psig. To find the fracture pressure at the top of the perforations, the hydrostatic pressure of the water in the wellbore between 6,891 (location of pressure gauge) and 7,025 feet was added to the 4,966 psig. The fracture pressure at 7,025 feet is 5,024 psig. This corresponds to a fracture gradient of 0.715 psi/ft. Based on this fracture gradient, the fracture pressure at the estimated depth of the uppermost perforation requested in the permit for this well (6,700 ft) is calculated to be 4,790 psi.

HYDROGEOLOGIC PROPERTIES

POROSITY

Compensated neutron and litho-density open-hole porosity logs run were run in the injection well. The neutron and density logs provide total porosity data. Effective porosity was determined by lab testing using helium porosimetery on a limited number of core plug samples. See Appendix A, the CCS #1 well completion report (Frommelt, 2010), for additional discussion about the helium porosimetery method.

A comparison was made between the neutron-density crossplot porosity (average neutron and density porosity) and core porosity (Figure 2-11). These porosity sources compared well. Consequently, the neutron-density crossplot porosity was used to estimate effective porosity.

Based on porosity trends, there are 7 major sub-intervals present in the Mt. Simon at the site. Table 2-1 lists the intervals identified and the average effective porosity of each. Based on the neutron-density crossplot porosity, the 68-foot injection interval (6,982-7,050 feet) has an average effective porosity of 21.0%.

Table 2 - 1 : Average effective porosity

Average effective porosity based on the neutron-density crossplot porosity for CCS #1. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs.

Sub-Interval (feet)	Effective Porosity (%)
5,545-5,900	10.8
5,900-6,150	8.72
6,150-6,430	10.1
6,430-6,650	15.2
6,650-6,820	21.8
6,820-7,050	18.7
7,050-7,165	9.84

PERMEABILITY

The intrinsic permeability, *k*, was directly available from the results of the core analyses and well testing in the injection well. However, to estimate permeability over a larger interval where core was not available, a relationship between core permeability and log porosity was required.

CORE ANALYSIS

A core porosity-permeability model was developed (Figure 2-12) based on grain size. Grain size was determined by use of the cementation exponent, *m*, from Archie's equation (Archie, 1942). This model was used with a neutron-density crossplot porosity to estimate permeability with depth. Average permeability for sub-intervals of the Mt. Simon is presented in Table 2-2. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot injection interval (6,982-7,050 feet) has an average intrinsic permeability of 194 mD (Frommelt, 2010).

Table 2 - 2 Average intrinsic permeabilities of the Mt Simon

Average intrinsic permeabilities of the Mt Simon sub-intervals, based on a model of core permeability and core porosity, estimated using a neutron-density crossplot porosity.

Sub-Interval (feet)	Intrinsic Permeability (mD)
5,545-5,900	19.4
5,900-6,150	10.2
6,150-6,430	8.44
6,430-6,650	8.21
6,650-6,820	8.64
6,820-7,050	107
7,050-7,165	4.37

WELL TESTING AND ANALYSIS

Three pressure falloff (PFO) tests of varying duration were conducted in September and October 2009 as part of the initial well completion (Frommelt, 2010). A PFO test involves two segments. During the first test segment, the reservoir is stressed by injecting fluid, which increases the reservoir pressure. During the second test segment, the reservoir pressure is monitored as it returns to its pre-test pressure. The initial perforations in the injection interval were 7,025 to 7,050 feet. Water treated with a clay-stabilizing potassium chloride was injected at 1.5 to 2.0 barrels per minute (bpm) (63 to 84 gallons per minute) for nearly two hours. A 19.5 hour PFO followed this injection period.

After this test, the perforations were acidized and a step-rate test was conducted. For the second step-rate test, treated water was injected at 3.1 bpm (130 gpm) for five hours, while pressure was monitored for approximately 45 hours.

The third PFO test was conducted after the well was fully perforated and stimulated. An additional 30 feet of perforations were added at 6,982 to 7,012 feet. The perforated zone received a second acid treatment. Additional information regarding perforations and acid treatment are described in the Completion Report, Appendix A (Frommelt, 2010). For the third PFO test, the treated water was injected at an increasing rate of 3.1 to 4.2 bpm (130 to 176 gpm) over 6.5 hours and then at 4.2 bpm (176 gpm) for an additional 6.5 hours. During this third PFO test, pressure was monitored for 105 hours.

PIE pressure transient software was used to analyze the pressure data for reservoir flow properties. Conventional semi-log, log-log and nonlinear regression analyses were used to analyze the data. (Well-Test Solutions, Ltd., http://welltestsolutions.com/index.html)

Only 25 feet of perforations were open in the very large vertical formation (gross thickness 1,506 feet) during the first PFO, so a partial penetration or partial completion effect was expected. The derivative (log-log plot) of the falloff test is used to qualitatively identify reservoir features including the partial penetration effect (Figure 2-13) and to determine permeability. Two radial, 2-dimensional responses (horizontal derivative) were measured during this test between 0.1 and 1 hrs (PPNSTB on Figure 2-13) and 20 to 100 hrs (STABIL on Figure 2-13). The first period corresponds to radial flow across the 25 feet perforated interval; the second period corresponds to the pressure response across a larger thickness that would be between two much lower permeability sub-units. The transition between the two radial responses (SPHERE on Figure 2-13) is a spherical flow (3-dimensional flow) period that is influenced by vertical permeability and provides insight into the ratio of vertical to horizontal permeability (k_v/k_h).

To observe the effect of the acid treatment and the second set of perforations to the overall injection interval, the derivatives of the three PFO tests were overlain (Figure 2-14). The data between 0.1 and 1.0 hrs match relatively well and the data between 1.0 and 100 hrs match very well. Similar trends of the first radial period, transition and final radial period indicates that the second set of perforations did not change the permeability estimated from the pressure transient tests. As such, the subsequent pressure transient analyses used a single layer, partial penetration model with 25 feet of perforations open at the base of the layer.

Simulation of the pressure transient data using analytical solutions (Figure 2-15), gave a permeability of 185 mD over 75 feet of vertical thickness. The transition period gave a vertical permeability over the 75 feet as 2.45 mD (k_v/k_h = 0.0133). The Mt. Simon initial pressure in the well at 7,025 feet was about 3,200 psig.

For the injection interval, the permeability estimates from the different methods are very close. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot, injection (perforated) interval (6,982 to 7,050 feet) has an average intrinsic permeability of 194 mD. Using the PIE pressure transient software for the third PFO, permeability was estimated to be 185 mD over 75 feet of vertical thickness. Permeability for this same 75 feet of rock was calculated using core and well log analyses. The permeability from this analysis was estimated to be 182 mD.

HYDRAULIC CONDUCTIVITY

Intrinsic permeability (*k*) and hydraulic conductivity (*K*) for a single-phase system are related according to the following equation (Freeze and Cherry, 1979):

$$K = k \rho g / \mu$$

where ρ= fluid density

g= gravitational acceleration
μ= dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Intrinsic permeability is also known as permeability. For the range of viscosity and density discussed, the hydraulic conductivity will vary. The 68-foot injection interval in the well (6,982 to 7,050 feet) has an average intrinsic permeability of 194 mD; this equates to a hydraulic conductivity of 3.9×10^{-4} cm/sec, using the in-situ formation fluid properties at this depth.

STORAGE COEFFICIENT

The storage coefficient or storativity, S, ranges from 5×10^{-5} to 5×10^{-3} for confined aquifers (Freeze and Cherry, 1979). S is commonly determined by well testing; however, S is a function of fluid compressibility (c_f) and rock compressibility (c_r) and can be estimated from the following equation:

$$S = \rho\, g\, h(c_r + \varphi\, c_f)$$

where ϕ= porosity
h= formation thickness
ρ= fluid density
g= gravitational acceleration

Rock compressibility can be expressed as the inverse of the bulk modulus (K_b) and in terms of the Young's modulus (E) and Poisson's ratio (v) (Huang and Rudnicki, 2006):

$$c_r = 1/K_b = 3(1 - 2v)/E$$

Gravitational acceleration, g, approximately equals 9.81 m/sec^2. For this calculation, the Mt. Simon is assumed to be 1,506 feet thick and have 10% porosity (Φ). Young's modulus (E) and Poisson's ratio (v) were determined, on samples collected at 6,761 and 6,770 ft in the injection zone, by Weatherford Laboratory (see CCS #1 Completion Report, Appendix A (Frommelt, 2010)). These values were used to compute c_r using the equation shown above. These compressibility values are consistent with bulk compressibility values for sandstone reservoirs, which ranged from 6.5×10^{-5} to 2.7×10^{-4} MPa^{-1} at 7,000 psi (48.3 MPa) confining pressure (Zimmerman, 1991). Fluid compressibility (c_f) is known to vary with pressure and temperature changes (Huang and Rudnicki, 2006). Using two samples collected from in the injection well (MDT-1 & MDT-4), fluid compressibility and storativity values were estimated (Table 2-4). Based on the range of values described here, storativity was estimated to range from 4.9×10^{-5} to 9.0×10^{-4} (Table 2-3). These values are consistent with values published by Freeze and Cherry (1979).

Table 2 - 3 Estimates of rock (cr) and fluid (cf) compressibility and storativity (S) for CCS #1

Depth (ft)	Pressure (psi)	Pressure (MPa)	T (°C)	ρ (g/L)	c_r (1/Mpa)	c_f (1/Mpa)	Φ (-)	h (m)	S (vol/vol)
5772	2582.9	1.78E+01	48.8	1089.7	2.02E-04	2.04E-04	0.132	459.0	8.59E-04
7045	3206.1	2.21E+01	52.1	1123.5	2.02E-04	1.83E-04	0.132	459.0	9.00E-04
5772	2582.9	1.78E+01	48.8	1089.7	3.68E-05	2.04E-04	0.132	459.0	4.87E-05
7045	3206.1	2.21E+01	52.1	1123.5	3.68E-05	1.83E-04	0.132	459.0	6.38E-05

2.2.3 Characteristics of Injection Zone Formation Water

Information on the injection zone formation water is primarily based on specific data obtained from the injection well during construction and logging (Frommelt, 2010). Fluid samples were collected from the open borehole after drilling and wireline geophysical testing were completed. MDT* modular formation dynamics tester and Quiksilver Probe* focused extraction of pure reservoir fluid tools were run on April 28 and 29, 2009, used to measure formation pressure and formation temperature and to collect high-quality reservoir fluid samples at five depths (Table 2-4). Prior to collecting a reservoir sample, MDT measures the fluid resistivity to help discriminate between formation fluids and drilling mud filtrate. Fluid sample volume varied from 450 mL to 900 mL. These samples were analyzed by the Illinois State Water Survey.

Table 2 - 4 Data for fluid samples collected from the Mt. Simon

Data for fluid samples collected from the Mt. Simon sandstone in CCS#1 using the MDT sampler in April 2009

Sample ID	Sample Depth (feet)	Formation Pressure (psi)	Formation Temperature (°F)	TDS (mg/L)	Density (g/L)
MDT-4	5,772	2,582.9	119.8	164,500	1,089.7
MDT-3	6,764	3,077.5	125.1	185,600	1,120.7
MDT-14	6,764	3,077.5	125.1	179,800	Not analyzed
MDT-5	6,840	3,105.9	125.0	182,300	1,124.1
MDT-2	6,912	3,141.8	125.8	211,700	1,136.5
MDT-9	6,840	3,105.9	125.0	219,800	Not analyzed
MDT-1	7,045	3,206.1	125.7	228,100	1,123.5
MDT-8	7,045	3,206.1	125.7	201,500	Not analyzed

The MDT tool provided provide in-situ formation and fluid properties (Table 2-4). Formation temperatures ranged from 119.8°F (48.8 °C) at a depth of 5,772 feet to 125.8°F (52.1°C) at depth of 6,912 feet._The formation pressure varied with depth and had a minimum pressure of 2,583 psi recorded at 5,772 feet and a maximum pressure of 3,206 psi recorded at 7,045 feet.

Laboratory measurements of samples provide fluid densities ranging between 1,090 to 1,137 g/L, with an average of 1,119 g/L. The method described by Kestin et al. (1981) was used to calculate the brine viscosity for the Mt. Simon brine because the formation predominantly NaCl brine. The was estimated to range between 5.4×10^{-4} to 5.7×10^{-4} Pa sec with an average of 5.5×10^{-4} Pa sec.

Salinity affects the storage capacity because it reduces CO_2 solubility in water. Figure 2-18 illustrates the relative density of deep aquifer brines in the Illinois Basin. Figure 2-19 shows the broad distribution of total dissolved solids (TDS) in the Mt. Simon which should exceed 60,000 mg/L over much of the Illinois Basin and 180,000 mg/L in the deeper portions of the basin. Figure 2-19 also shows the approximate position of the 20,000 mg/L TDS iso-concentration line for the Mt. Simon Sandstone in the northern part of the State. South of this line, the groundwater is expected to exceed 20,000 mg/L TDS. At the site the TDS of samples varied with depth (Table 2-4), with TDS of 164,500 mg/L TDS at 5,772 feet and 228,100 mg/L TDS at 7,045 feet. The average TDS for the eight samples is 196,700 mg/L.

Little information is available about the potentiometric surface in the Mt. Simon sandstone in Macon County because very few wells penetrate the Mt. Simon in central Illinois. Using the formation pressure (p) and fluid density (ρ) data (Table 2-4), the potentiometric head (h) was calculated using the relationship $p = \rho gh$, where g is the gravitational constant. The mean potentiometric head in the Mt. Simon has an elevation 249.5 feet MSL. If the well were filled with freshwater (ρ= 1,000 g/L), the potentiometric head would have an elevation of 996.1 feet MSL.

2.3 CONFINING ZONES

The primary confining zone (seal) is the Cambrian-age Eau Claire formation (Figure 2-8). Based on the data from CCS #1, the Eau Claire has a total thickness of 497.5 feet. The shale section of the Eau Claire has a thickness of 198.1 feet and is the lowermost section within the formation.

2.3.1 Primary Overlying Zone: Regional Information

Information on the upper confining zone, the Eau Claire formation, is based on specific data obtained from the injection well installation (Frommelt, 2010) and is supplemented by regional geologic information from ISGS studies and reports. In order for a saline reservoir to be used for storage of $CO_{2,}$ there must be an effective hydrologic seal that restricts upward fluid movement. Within the Illinois Basin, three thick and wide-spread shale units function as major regional seals. These units are the Cambrian-age Eau Claire Formation, the Ordovician-age Maquoketa Formation, and the Devonian-age New Albany Shale (Figure 2-8). The Eau Claire formation has no known penetrations (with the exception of injection and verification wells at the site) within a 17-mile radius surrounding site; therefore, integrity of wellbores should not be a risk.

The formation is composed primarily of a silty, argillaceous dolomitic sandstone or sandy dolomite in northern Illinois and becomes a siltstone or shale in the central part of the Illinois Basin (Willman et al., 1975). In the southern part of the basin, the Eau Claire is a mixture of dolomite and limestone with some fine-grained siliciclastics.

Gas storage projects in the Illinois Basin confirm that the Eau Claire is an effective seal in the northern and central portions of the Basin. Core analysis data from the Manlove Gas Storage

Field, 37 miles to the northeast of the proposed site, show that the Eau Claire shale intervals have vertical and horizontal permeability less than 0.1 mD.

A north-south cross section of the Basin through the central part of Illinois (Figure 2-20) shows that the Eau Claire Formation has a laterally persistent shale interval above the Mt. Simon.

2.3.2 Primary Overlying Confining Zone: Site-Specific Information

Wireline logs from the injection well and two geologic cross sections near the proposed site (Figures 2-6 and 2-7) indicate that there is about 500 feet of Eau Claire formation directly above the Mt. Simon Sandstone. At the site the Eau Claire Formation occurs at a depth of 5,047 feet to 5,545 feet below ground surface. The shale section of the Eau Claire occurs at a depth of 5,347 to 5,545 feet. In the injection well, the upper section of the Eau Claire (5,047 to 5,347 feet) is a dense limestone with thin stringers of siltstone.

The lower section of the Eau Claire (5,347 to 5,545 feet) consists of shale. X-ray diffraction data indicate that the mineralogy of the shale includes 60 percent clay minerals and 37 percent quartz and potassium feldspar. The shale is laminated and dark gray to black in color.

Geomechanical data collected through lab and field testing determined the elastic parameters for a single Eau Claire shale sample. A field test, a mini-frac test, was conducted to determine the in situ fracture pressure. The Eau Claire shale sample was collected at a depth of 5,478.5 feet. This sample was tested by Weatherford Labs (Houston, TX) and yielded the following properties—Young's modulus of 5.50×10^6 psi, Poisson's ratio of 0.27, bulk modulus of 3.92×10^6 psi and shear modulus of 2.17×10^6 psi.

"Mini-frac" testing was conducted within the Eau Claire, employed to determine the effectiveness of the shale as a caprock seal (Frommelt, 2010). A mini-frac test using MDT was conducted across a 2.8-foot shale interval in the Eau Claire, centered at a depth of 5,435 feet. Mini-frac tests are very small volume tests that inject fluid up to the parting pressure of the formation.The test was designed for four short-term injection/falloff test periods (15 to 60 minutes in duration). The fracture pressure from these four tests ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft.

None of the CCS #1 sidewall rotary core plugs penetrated shale. None of the individual shale layers at the inch to centimenter scale from the whole core collected from the Eau Claire were thick enough for obtaining a core plug for permeability analyses,. However, 12 plugs were available for porosity and permeability testing within the Eau Claire interval. The plugs consisted of very fine grained sandstones, microcrystalline limestone, and siltstone. Because sidewall rotary core plugs are taken horizontally, the permeability data from these plugs indicate the horizontal (not vertical) permeability. The average horizontal permeability for the 12 sidewall rotary core plugs is 0.000344 mD. The average vertical permeability for the upper confining shale layer is expected to be well below 0.000344 mD because this value is based on the non-shale horizontal permeability values and the vertical permeability of shales should yield even lower values.

The Illinois State Geological Survey database of UIC wells with core from the Eau Claire was also used to characterize the upper confining seal. This database shows that the Eau Claire's median permeability is 0.000026 mD and median porosity is 4.7%. At the Ancona Gas Storage Field, located approximately 80 miles to the north of the injection site, cores were obtained through 414 feet of the Eau Claire, and 110 analyses were performed on a foot-by-foot basis. Most vertical permeability analyses showed values of <0.001 to 0.001 mD. Only five analyses were in the range of 0.100 to 0.871 mD, the latter being the maximum value in the data set. This indicates that even the more permeable beds in the Eau Claire formation are expected to be relatively tight and act as confining lithologies.

Fluid samples were not collected from the Eau Claire due to its low permeability, so the properties of fluid sample MDT-4 (Table 2-4), which was the Mt. Simon brine sample collected closest to the Eau Claire, were used to estimate the dynamic viscosity and hydraulic conductivity using the equations outlined above. The fluid sample properties included a temperature of 119.8°F and density of 1,089.7 g/L. The dynamic viscosity was estimated to be 758.0 µPa sec. The hydraulic conductivity is estimated to be 4.8×10^{-14} cm/sec based on the measured intrinsic permeability value of 0.000344 mD.

2.3.3 Secondary Confining Zones Proposed, Include Explanation and Depth Interval(s)

Secondary confining zones will provide containment of the CO_2 should an unlikely failure of the primary confining zone occur. The secondary seals listed here are units with low permeability that are regionally present and serve as confining seals for oil, gas and gas storage fields throughout Illinois.

Examination of the wireline logs in the injection well and regional studies indicate that there are two laterally continuous, secondary seals at the site (Frommelt, 2010). The Ordovician-age Maquoketa Shale is 206 feet thick at the well site with the top at a depth of 2,611 feet. This shale is a regional seal for hydrocarbon production from the Ordovician Galena (Trenton) Limestone. The top of the Devonian-Mississippian-age New Albany Shale (Figure 2-21) is at a depth of 2,088 feet and is about 126 feet thick at the well site. Extensive data from oil fields through the Illinois Basin show that this shale is an excellent seal for hydrocarbons; hence, it should also be an excellent seal against the vertical migration of CO_2 at this site. In addition to the two major secondary confining units, there are also many minor, thinner Mississippian- and Pennsylvanian-age shale beds that will also provide barriers against CO_2 vertical migration.

2.3.4 Lower Confining Zone

The lower confining unit is Precambrian granite (Frommelt, 2010). At the site, the top of the Precambrian granite is at a depth of 7,165 feet. The ISGS could not find any available data on fracture pressure of granites in Illinois and no tests were conducted during construction of the injection or verification wells to determine the fracture pressure of the lower confining zone.

Sixty-five feet of granite was drilled at during construction of the injection well. One sidewall core was collected at 7,200 feet. Testing of the core indicated the permeability to be 0.0091 mD. Using the pressure and fluid properties obtained from the closet fluid sample recoverd in the Mt Simon, MDT-1 (Table 2-4), the hydraulic conductivity for the granite is estimated to be $1.8x10^{-12}$ cm/sec. Because the lower confining zone is the basement granite and no other sedimentary rocks are below the granite the fracture pressure, porosity, and permeability of the granite will not impact injection or fluid migration as the CO_2 injection interval is above this interval and the CO_2 is expected to move upward away from the granite.

2.4 FAULTS, FRACTURES, AND SEISMIC ACTIVITY.

Regional mapping (Nelson, 1995), and 2D and 3D seismic surveys in the vicinity of the proposed site do not indicate the presence of faulting at the injection site (Leetaru, 2011). There are no regional faults or fractures mapped within a 25-mile radius of the proposed site (Figure 2-1). Seismic reflection data were acquired over the site to identify the presence of faults and geologic structures in the vicinity of the proposed well site. Three-dimensional (3D) seismic reflection data acquired 3D at the site shows no evidence of faulting through either the Mt. Simon Sandstone injection interval or the Eau Claire formation primary sealing interval. Higher resolution 3D vertical seismic profiles (VSP) also acquired at injection site do not show any breaks in continuity that are associated with faults. Interpretations of the seismic reflection data suggest that no faults or fractures are visible at the proposed injection site (Figures 2-2 through 2-4).

Since 1973, two earthquakes have been recorded within 100 km of the proposed injection site: a magnitude 3.0 quake on April 24, 1990 in Coles County approximately 41 miles to the southeast, and a magnitude 3.2 quake on January 29, 1993 in Fayette County approximately 58 miles to the south-southwest (http://earthquake.usgs.gov/earthquakes/eqarchives/epic/epic_circ.php, USGS Earthquake Search, as of March 17, 2011).

The relative seismic risk at the site is considered minimal. The probability of an earthquake of magnitude 5.0 or greater within 50 years and within 50 km is less than 1% (USGS 2009 PSHA model for Decatur, Illinois, https://geohazards.usgs.gov/eqprob/2009/). There exists a 2% probability that the Peak Ground Acceleration due to seismic activity will exceed 10% G within 50 years (http://earthquake.usgs.gov/earthquakes/states/illinois/hazards.php). Thus, the risk of seismic activity breaching the integrity of the well or the injection formation is considered minimal.

2.5 GROUNDWATER AND UNDERGROUND SOURCES OF DRINKING WATER

2.5.1 *Characteristics of the Aquifer Immediately Overlying the Confining Zone*

The saline formation imediatley overlying the Eau Claire confining unit is the Cambrian–age Ironton-Galesville formation (Figure 2-8). Based on the geophysical logging in the injection well, the Ironton-Galesville is 119 ft thick and is present between 4,928 to 5,047 feet in depth (Frommelt, 2010). This thickness is within the range of estimates for the Ironton-Galesville formation in region, between 100 and 150 feet, (Figure 2-22). The Ironton and Galesville Sandstones are considered here as one unit because they are comprise a single aquifer in the northern part of Illinois (Willman et al., 1975). The two sandstones are difficult to differentiate from each other using wireline logs. The Ironton is a relatively poorly sorted, fine- to coarse-grained, dolomitic sandstone. The Galesville is a sandstone, better sorted, finer grained, and has higher porosity than the overlying Ironton. The site wells are the only wells that penetrated this zone within a 17-mile radius of the proposed site.

Little information is available about the potentiometric surface or TDS of the Ironton-Galesville Formation in Macon County because very few wells penetrate the Ironton-Galesville in central Illinois. The pressures in the Illinois Basin are generally normally pressured at 0.433 psi/ft or slightly greater, depending upon reservoir salinity, so the potentiometric surface of the Ironton-Galesville formation is approximated to be at surface elevation of 670 feet MSL. No potentiometric data were collected during drilling of CCS #1 for the Ironton-Galesville._The closest well with TDS data is the Allied Chemical Waste Disposal Well #1 in Vermillion County (about 73 miles from the site). The well penetrated the Ironton-Galesville at a depth of 4,096 feet measured depth. The total dissolved solids were measured to be 112,000 mg/L in this well (Brower et al, 1989). In addition, regional mapping of the formation by the USGS shows that the formation fluid in this formation at the site should be saline (Figure 2-23).

2.5.2 Underground Sources of Drinking Water

Sand and gravel aquifers are found in the Quaternary and recent geologic deposits. Larson et al. (2003) described these deposits for DeWitt, Piatt, and northern Macon Counties (Figure 2-24). While the water quality of groundwater in these aquifers is not known precisely, these aquifers are used for water supplies and are considered to be Underground Sources of Drinking Water (USDW). The vertical sequence of sand and gravel aquifers in Macon County is illustrated in Figure 2-25. Several sand and gravel aquifers are present. The deepest aquifer is the Mahomet aquifer, which is a major aquifer capable of yielding significant amounts of water (usually greater than 1,000 gpm). Other aquifers are found in the Banner formation, the Glasford formation, and more recent sediments. The Mahomet aquifer is not located beneath the site (Figure 2-26), but is present approximately 5 miles to the north. Sand and gravel aquifers are likely to be thin or absent in the Banner formation (Figure 2-27), the lower portion of the Glasford formation (Figure 2-28), and the more recent sediments (Figure 2-29). Sand and gravel aquifers are likely to be 5 to 20 feet thick in the upper portion of the Glasford formation (Figure 2-30) and are likely found within 100 feet of the ground surface.

Water well records were found in the Illinois State Water Survey (ISWS) database indicate that three private water supply wells are located in these strata in the southeast quarter of Section 32 (Figure 2-35, Table 2-5). These wells are likely to be the closest wells downgradient from the injection well.

Table 2 - 5 Description of nearest potable water wells in Section 32, T17N, R3E

API #	Well Owner	Well Depth (ft)	Well Diameter (in)	Year Drilled
121152203900	Gary Sebens	55	36	1988
121152221200	Gary Sebens	38	36	1990
121152283500	Anna Stiles	56	36	1992

Water quality data for the Mississippian bedrock is not available at the site or in Macon County. Regional data were compiled by Brower et al. [1989], Larson et al. [2003], and Poole et al. [1989] and are the only source for data at the site. They noted that mineralization of groundwater in the Valmeyeran and Chesterian units of the Mississippian System was low in outcrop (actually subcropping beneath Quaternary strata) areas and reached a maximum of 100,000 to 160,000 mg/L TDS in the Illinois Basin (Figure 2-34). Groundwater with low TDS occurs only in and near the outcrop/subcrop areas except in the broad area between the Illinois and Mississippi Rivers. There are no Mississippian unit outcrop/subcrop areas in Macon County. Figure 2-34 shows the estimated position at which 10,000 mg/L TDS groundwater is encountered in the Valmeyeran and Chesterian, respectively. Based on available data it is not expected that the Mississippian System at the site will be a USDW.

Pennsylvanian-age bedrock is the uppermost bedrock at the site (Figure 2-31). It is considered the lowest USDW at the site at a depth of 140 ft. The potentiometric surface of lowest USDW is approximately 55 to 59 feet below the ground surface, based on potentiometric data collected from the four groundwater compliance monitoring wells at the site during the 4th quarter of 2010 (Locke and Mehnert, 2010).

Illinois State Geological Survey (ISGS) cross sections of the formation were constructed to assist the Illinois Department of Natural Resources, Office of Mines and Minerals (IDNR-OMM) determine the depth of surface casing in hydrocarbon wells needed to protect underground sources of drinking water (USDW). The cross-section for Christian and Macon Counties, as shown in Figures 2-32 & 2-33 (Vaiden, 1991) were developed using water quality data from the ISWS and estimates from geophysical logs using the technique of Poole et al. (1989). The source of the water quality data is noted on the cross-section. The cross-section indicates that the water quality in the uppermost Pennsylvanian bedrock is less than 10,000 mg/L, but the TDS rapidly increases below the No. 2 Coal (Figures 2-32, 2-33 & 2-34) and generally exceeds 10,000 mg/L. Field investigations to determine the lowermost USDW at the site are discussed in a letter from Dean Frommelt of Archer Daniels Midland Company (ADM) to Illinois EPA, dated September 29, 2009. In a December 2, 2009 letter (Nightingale, 2009), the Illinois EPA approved the monitoring of the Pennnsylvanian bedrock as the lowermost USDW at the site.

2.6 MINERALS AND HYDROCARBONS

2.6.1 Mineral or Natural Resources beneath or Near the Site

Sand and gravel resources are commonly present in the low terraces and floodplain of the Sangamon River and its tributaries. Several sand and gravel pits have operated in the area in the past and currently there are one active and two idle operations in or near the project area. The nearest active sand and gravel pit is approximately 12 miles to the west-southwest of the site. Relatively thick limestone deposits, suitable for construction aggregates, generally occur at depths greater than 1,100 feet. Access to these limestones is possible only through underground mining methods, which is not economically feasible at the present time.

A review of the known coal geology within a five mile radius of the site indicates that although several high-sulfur coals are present throughout the area, only the Springfield coal has a thickness between 42 and 66 inches, which is considered mineable. Mining is restricted today due to urbanization and commercial development at the surface. The restriction extends to five miles in all directions except to the north, north-east and east, where the coal is technically "available" for mining although not necessarily economically mineable at the present time. The top of the Springfield coal at the site is 647 feet and its thickness, based on geophysical log analysis, is about 4 to 5 feet thick. In general, the coal bed dips gently eastward as the depth of the coal ranges in depth from 500 feet five miles west of the site, to 725 feet five miles east of the site. .

The nearest active coal mines are the Viper Mine (about 35 miles west-northwest in Logan County) and Crown III Mine (operated by Springfield Coal Company, about 65 miles southwest in Macoupin County). The nearest historical coal mining on record at the ISGS were the three mines in Decatur. The closest is within 5 miles of the proposed site, the Decatur No. 1 Mine. The shaft for this mine was northeast of the intersection of Eldorado and Jefferson Streets in Decatur and was about 600 feet deep. This longwall mine has no surviving map of the workings, but the main haulage entry was shown on the adjacent mine map, Macon County No. 2 Mine, which was connected underground. The Decatur No. 1 Mine operated from 1879 until 1914. The reported production was 1,780,000 tons, which would have undermined about 475 acres. The adjacent Macon County No. 2 Mine produced 2,660,000 tons, and undermined 430 acres. The portions of the only surviving map indicate that these mines operated west of Illinois Route 47/121. The third mine in Decatur is farther southwest, near the intersection of US Route 51 and Cantrell Street in Decatur. The Macon County No. 1 Mine operated from 1903 until 1947 and produced 4,590,000 tons. This production undermined over 670 acres. All of these mines recovered the Springfield coal.

The presence of other unlocated or unrecorded old coal mines is unlikely. The first recorded coal exploration was in 1875, but coal was not found until 1876. The great depth to the coal prevented small operators from opening the type of local mines that prevailed in many other counties.

Oil and natural gas have been produced from both oil fields and solitary wells in the region. The largest of these oil fields is the Forsyth Field, northwest of the site (Figure 2-35) additionally the Oakley field is about 3.5 miles east of the site and the Decatur field is about 6 miles west of the site. The Forsyth and Decatur fields produce from Silurian strata between depths of about of 2,070 and 2,200 feet and 2000 and 2500 feet, respectively. The producing zone in the Forsyth is usually about 10 feet thick. The producing zone in the Decatur field is between 10 and 20 feet thick. In 2008, 6,100 barrels (bbls) of oil were produced from 48 producing wells in the Forsyth and total cumulative production for the field is 650,100 bbls by the end of 2008. Also in 2008, 400 bbls of oil were produced from 9 producing wells in the Decatur field with total production for the field at 49,900 bbls by the end of 2008. The Oakley field produces from Devonian strata between depths of about of 2,255 and 2,310 feet. The producing zone is usually about 5 to 25 feet thick. In 2008, 1,200 bbls of oil were produced from 2 producing wells. The total production for the field is 43,100 bbls of oil, as of the end of 2008.

Two single wells produced oil from Silurian strata in the vicinity of the site. The Decatur North well located about 1 mile from the injection well site. The well produced 125 barrels from a depth of 2,220 to 2,224 feet. This well was plugged in late 1954 after eight months of production. The other well was drilled in 1984 and abandoned in 1993. It produced from depths between 2,040 to 2,050 feet with a total production of about 2,200 bbls.

Natural gas is produced from several wells in the area that were drilled primarily for water. The gas is produced from Pleistocene sediments at depths of about 80 to 110 feet deep. The gas is suitable for domestic or agricultural usage but not for commercial development as a natural gas field.

2.7 REFERENCES

Archie, G.E., 1942. The electrical resistivity log as an aid in determining some reservoir characteristics: Journal of Petroleum Technology, v. 5, p. 54-62.

Bickford, M.E., W.R. Van Schmus, and I. Zietz, 1986. Proterozoic history of the mid-continent region of North America: Geology, vol. 14, no. 6, pp. 492–496.

Bond, D.C., 1972. Hydrodynamics in deep aquifer of the Illinois Basin, Illinois State Geological Survey Circular 470, Urbana, IL, 72 p.

Bowen, B.B., R.I. Ochoa, N.D. Wilkens, J. Brophy, T.R. Lovell, N. Fischietto, C.R Medina, and J.A. Rupp, 2011. Depositional and Diagenetic Variability Within the Cambrian Mount Simon Sandstone: Implications for Carbon Dioxide Sequestration: Environmental Geosciences, v. 18, p. 69-89.

Bredehoeft, J.D., C.R. Blyth, W.A. White and G.B. Maxey, 1963. Possible mechanism for concentration of brines in subsurface formations. Bulletin of the American Association of Petroleum Geologists 47(2): 257-269.

Brower, R. D., A. P. Visocky, I. G. Krapac, B. R. Hensel, G. R. Peyton, J. S. Nealon and M. Guthrie, 1989. Evaluation of underground injection of industrial waste in Illinois, Illinois Scientific Surveys Joint Report 2: 89.

Byers, D., 2011. Personal communication, Illinois State Geological Survey.

Cartwright, K., 1970. Groundwater discharge in the Illinois Basin as suggested by temperature anomalies: Water Resources Research, vol. 6, no. 3, p. 912-918.

Chenoweth, C., and A. Louchios, 2004. Directory of Coal Mines in Illinois, 7.5-minute Quadrangle Series: Decatur Quadrangle, Macon County, Illinois. Illinois State Geological Survey, 12 p., with “Coal Mines in Illinois – Decatur Quadrangle, Macon County, Illinois”, Illinois State Geological Survey Maps (1:24,000).

Driese, S.G., C.W. Byers, and R.H. Dott, Jr., 1981. Tidal deposition in the basal Upper Cambrian Mt. Simon Formation in Wisconsin: Journal of Sedimentary Petrology, v. 51, no. 2, p. 367–381.

Droste, J.B., and R.H. Shaver, 1983. Atlas of early and middle Paleozoic paleogeography of the southern Great Lakes area: Indiana Department of Natural Resources, Indiana Geological Survey, Special Report 32, 32 p.

Earlougher, Jr., R.C., 1977. *Advances in Well Test Analysis*, Monograph Series, Society of Petroleum Engineers of AIME, Dallas.

Finley, R., 2005. An Assessment of Geological Carbon Sequestration Options in the Illinois Basin: Final Report to the United States Department of Energy, Contract: DE-FC26-03NT41994, 581p. Finley, Robert, Principal Investigator, December 31, 2005.

Freeze, R.A. and J.A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

Frommelt, D., 2010. Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, Archer Daniels Midland Company – UIC Permit UIC-012-ADM, dated May 5, 2010.

Gupta, N. and E.S. Bair, 1997. Variable-density flow in the midcontinent basins and arches region of the United States, Water Resources Research, 33(8): 1785-1802.

Hester, N.C., 1969. Sand and gravel resources of Macon County, Illinois: Illinois State Geological Survey Circular 446, 16 p.

Huang, T. and Rudnicki, J.W., 2006. A mathematical model for seepage of deeply buried groundwater under higher temperature and pressure, Journal of Hydrology, Vol. 327, 42-54.

Kestin, J., E. Khalifa and R.J. Correia, 1981. Tables of dynamic and kinematic viscosity of aqueous NaCl solutions in the temperature range 20-150°C and the pressure range 0.1-35 MPa. *Journal of Physical and Chemical Reference Data,* 10(1): 71-87.

Kolata, D.R., 1991. Illinois basin geometry, in M.W. Leighton, D.R. Kolata, D.F. Oltz, and J.J. Eidel, eds., Interior cratonic basins: American Association of Petroleum Geologists, Memoir 51, p. 197.

Illinois Annual Oil Field Reports, Illinois State Geological Survey, various years.

Illinois State Geological Survey Mt. Simon database

Illinois State Geological Survey, 2006. Directory of Coal Mines in Illinois, Logan County, 10 p.

Illinois State Geological Survey, 2006. Directory of Coal Mines in Illinois, Macoupin County, 17 p.

ISGS County Coal Map Data, Macon County, Illinois: available on the ISGS Coal Section website at: http://www.isgs.uiuc.edu/maps-data-pub/coal-maps/counties/macon.shtml

ISGS ILWATER database available at: http://www.isgs.uiuc.edu/maps-data-pub/wwdb/launchims.shtml

Kolata, D.R., 2005. Bedrock Geology of Illinois, Illinois State Geological Survey Illinois Map 14: 1:500,000.

Lamar, J.E., 1964. Subsurface limestone resources in Macon County: Illinois State Geological Survey Unpublished Manuscript 141

Leetaru, H.E., D.G. Morse, R. Bauer, S. Frailey, D. Keefer, D. Kolata, C. Korose, E. Mehnert, S. Rittenhouse, J. Drahovzal, S. Fisher, J. McBride, 2005. Saline reservoirs as a sequestration target, in An Assessment of Geological Carbon Sequestration Options in the Illinois Basin, Final Report for U.S. DOE Contract: DE-FC26-03NT41994, Principal Investigator: Robert Finley, p 253-324

Leetaru, H., 2011. Personal communication, Illinois State Geological Survey.

Larson, D.R., B.L. Herzog and T.H. Larson, 2003. Groundwater Geology of DeWitt, Piatt, and Northern Macon Counties, Illinois. Champaign, IL, Illinois State Geological Survey Environmental Geology 155: 35.

Loyd, O,B. and W.L. Lyke, 1995. Ground Water Atlas of the United States, Segment 10: Illinois, Indiana, Kentucky, Ohio and Tennessee, United States Geological Survey Hydrologic Investigations Atlas 730-K, 30 p

Morse, D.G., and H.E. Leetaru, 2005. Reservoir characterization and three-dimensional models of Mt. Simon Gas Storage Fields in the Illinois Basin: Illinois State Geological Survey, Circular 567, 72 p. CD-ROM.

Nelson, W.J., 1995. Structural features in Illinois, Illinois State Geological Survey Bulletin 100, 144 p.

Nightingale, S. 2009. Letter to Archer Daniels Midland Company, Subject: Lowermost underground source of drinking water (USDW), Permit No. UIC-012-ADM, Log No. PS09-206, dated December 2, 2009.

Poole, V.L., K. Cartwright and D. Leap, 1989. Use of Geophysical Logs to Estimate Water- Quality of Basal Pennsylvanian Sandstones, Southwestern Illinois. Ground Water 27(5): 682- 688.

Quarterly Groundwater Report For Illinois EPA Underground Injection Control Permit Number UIC-012-ADM (2010 Q4), Locke, R. and Mehnert, E. December 17, 2010.

Sargent, M.L., and Z. Lasemi, 1993. Tidally dominated depositional environment for the Mt. Simon Sandstone in central Illinois: Great Lakes Section, Geological Society of America, Abstracts and Programs, v. 25, no. 3, p. 78.

V. Smith, personal communication, Schlumberger Carbon Services, 2011

Treworgy, C., C. Korose, C. Chenoweth, and D. North, 2000. Availability of the Springfield Coal for Mining in Illinois, Illinois State Geological Survey, Illinois Minerals 118.

Vaiden, R.C., 1991. Christian and Macon Counties, Cross-Section E-E’

Willman, H.B., E. Atherton, T.C. Buschbach, C. Collinson, J.C. Frye, M.E. Hopkins, J.A. Lineback, and J.A. Simon, 1975. Handbook of Illinois Stratigraphy, Illinois State Geological Survey Bulletin 95, 261 pp.

Zimmerman, R.W., 1991. Compressibility of sandstones, Elsevier Publishing Co., Amsterdam.

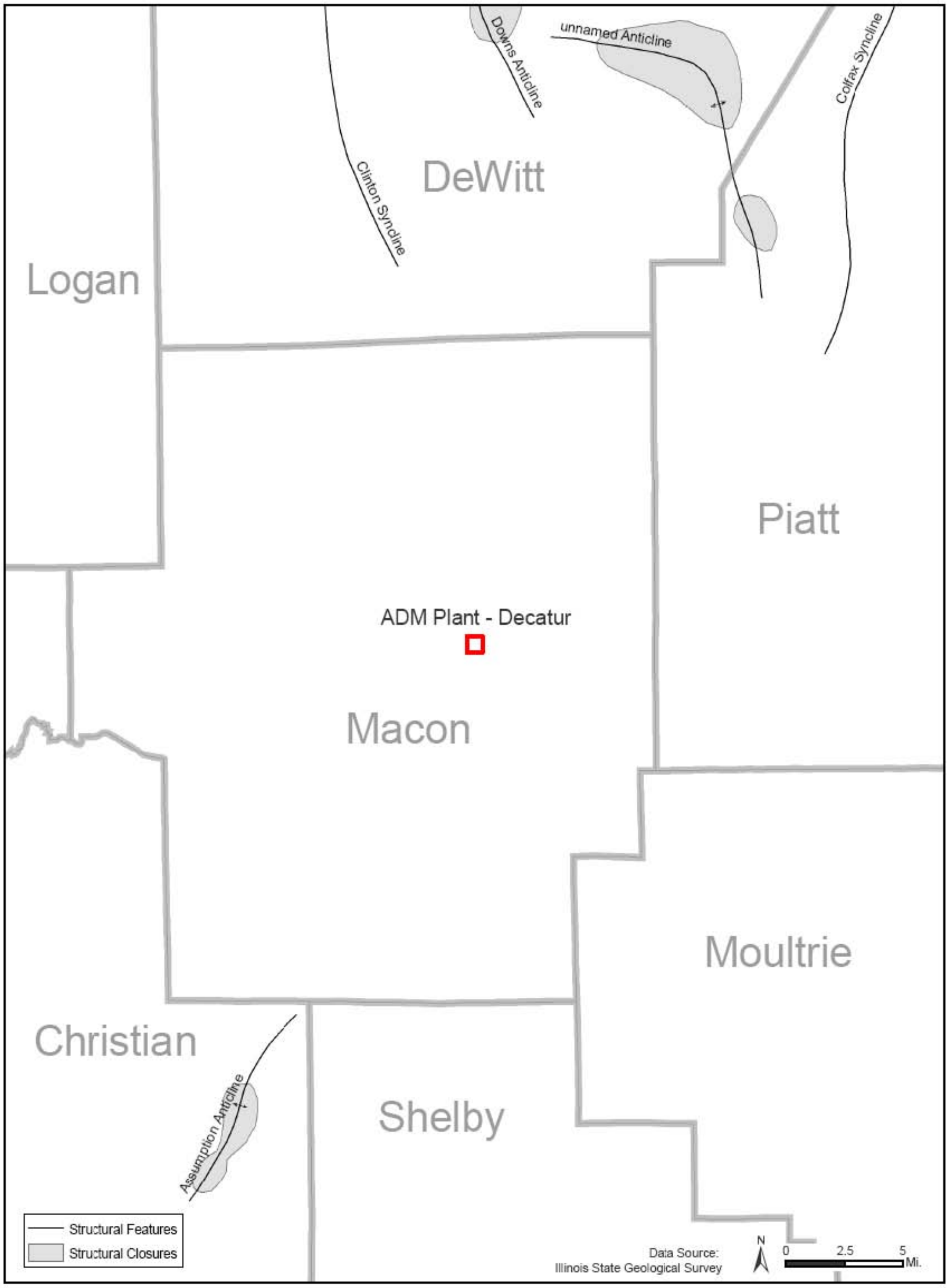


Figure 2 - 1 Regional structure map

Regional structure map showing no regional structures within a 25-mile radius of the ADM Plant near Decatur, Macon County. Source: Illinois State Geological Survey.

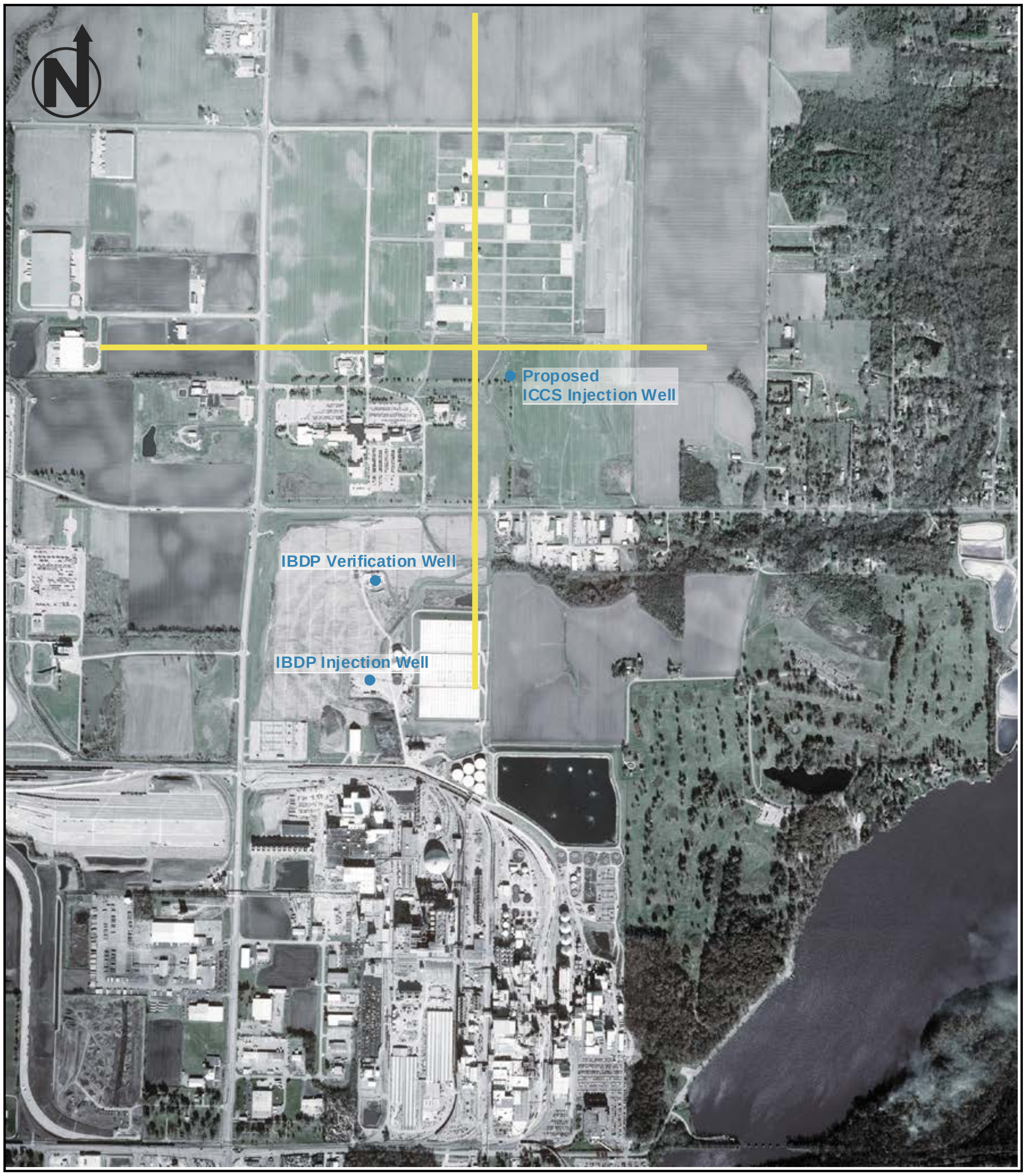


Figure 2 - 2 Aerial photo over the injection site.

The yellow lines denote seismic lines that were recorded. Reference Figures 2-3 and 2-4 for corresponding geologic cross-sections. Source: Byers, ISGS, 2011

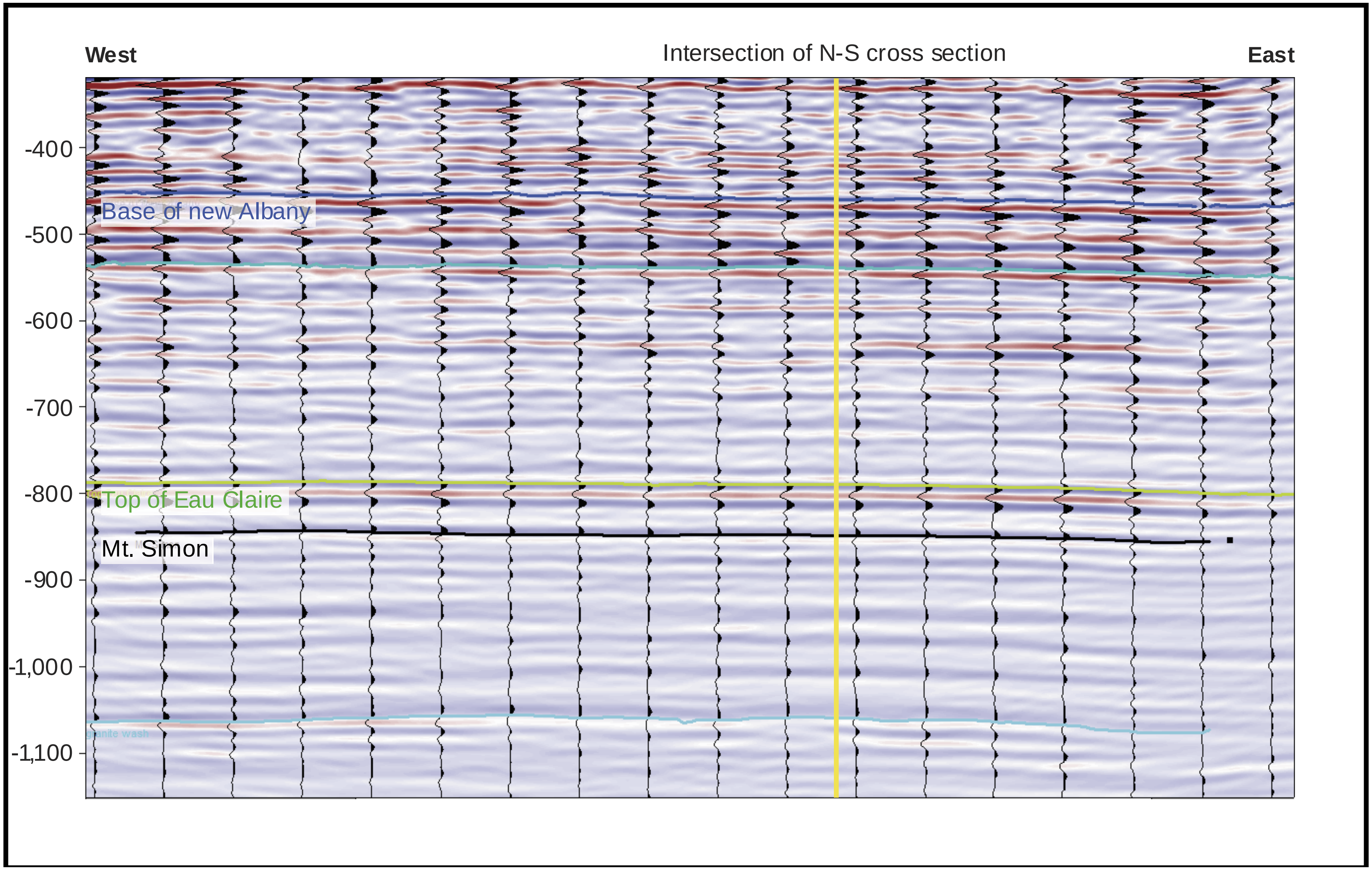


Figure 2 - 3 East-West seismic reflection profile near the injection site.

Source: Leetaru, 2011

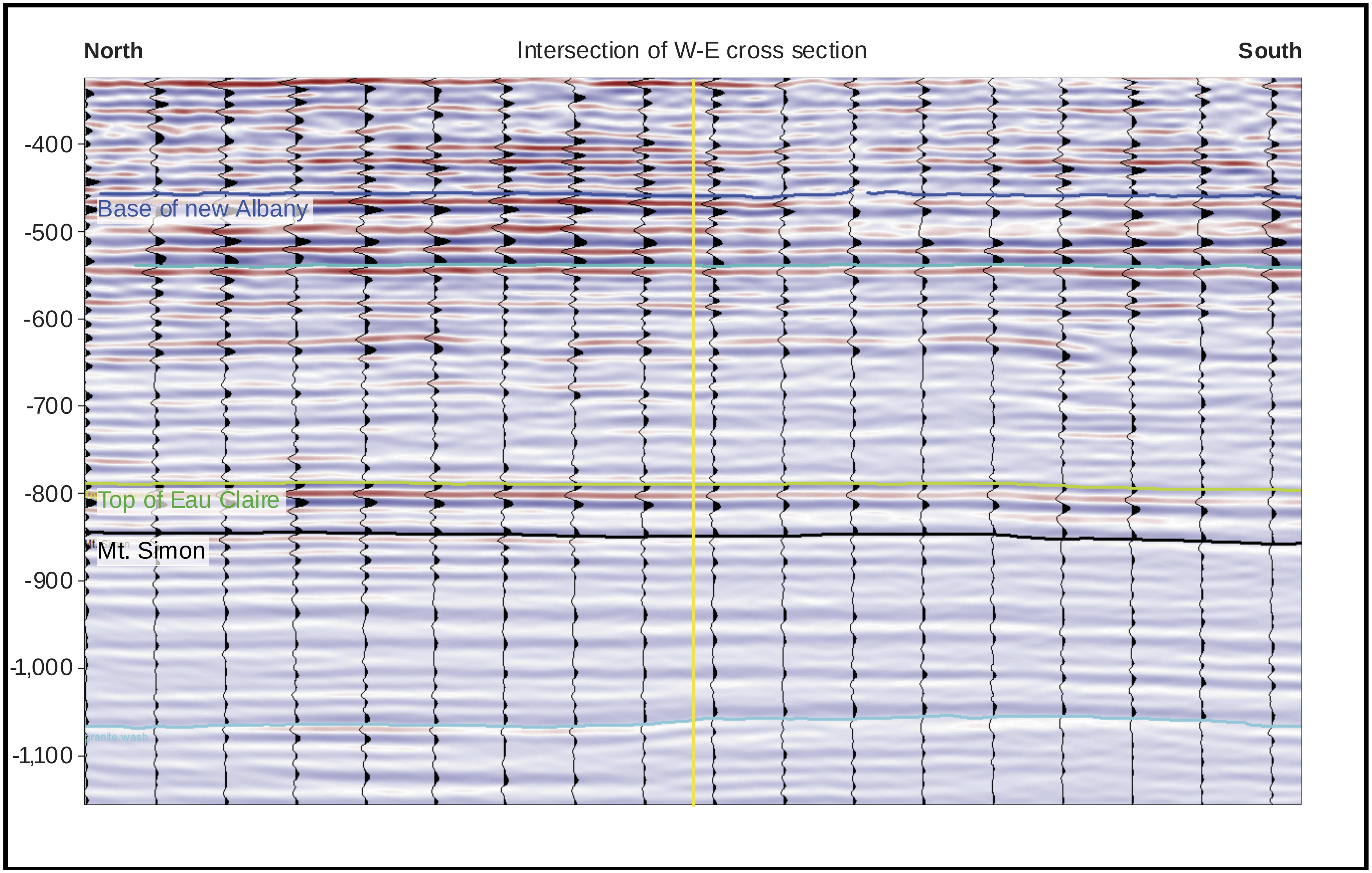


Figure 2 - 4 North-South seismic reflection profile near the injection site

Source: Leetaru, 2011

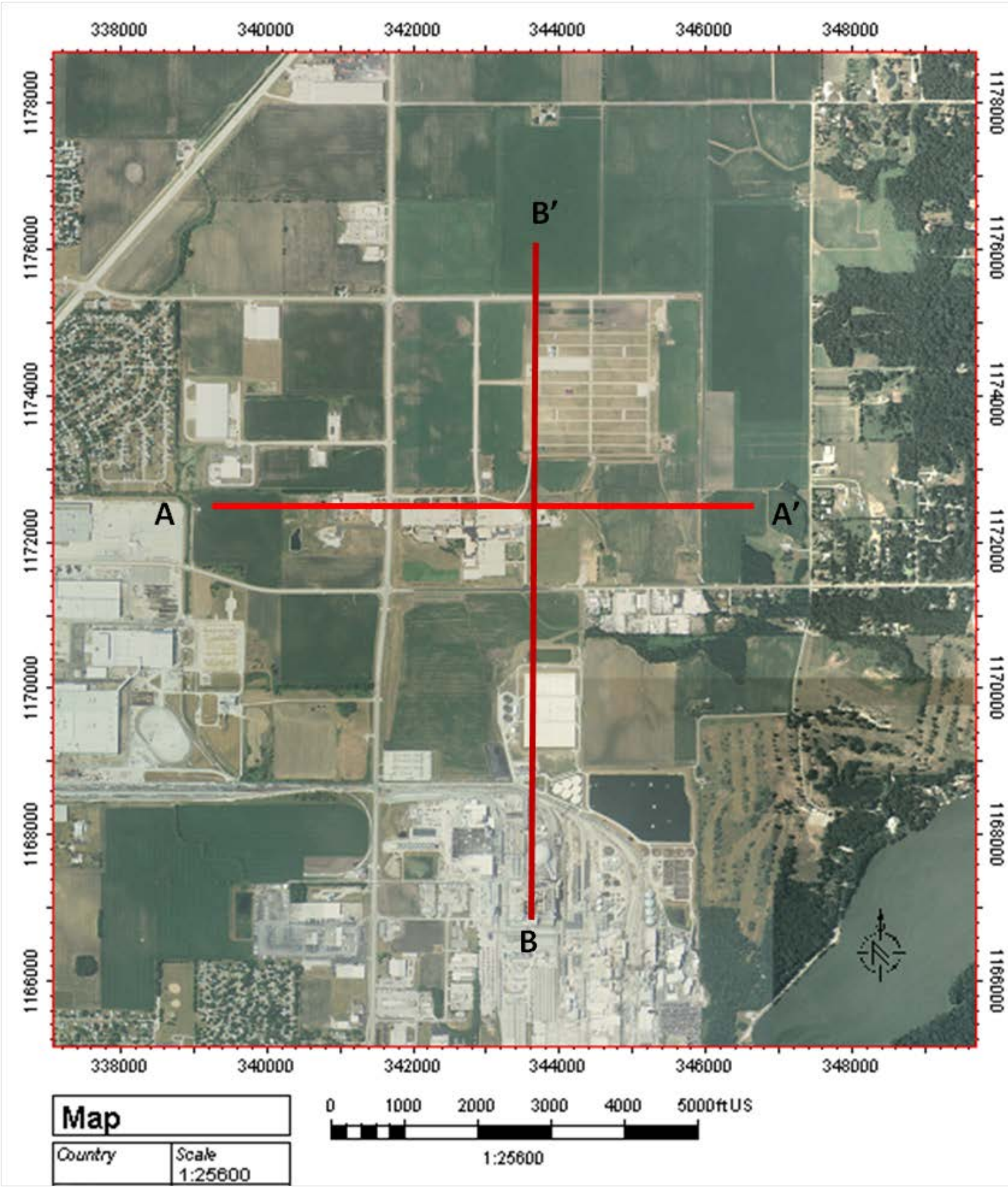


Figure 2 - 5 Location of cross-sections illustrating the regional geology

Location of cross-sections illustrating the regional geology of the injection site (Figure 2-6 and 2-7 are cross-sections referenced). Source: Smith, Schlumberger Carbon Services, 2011

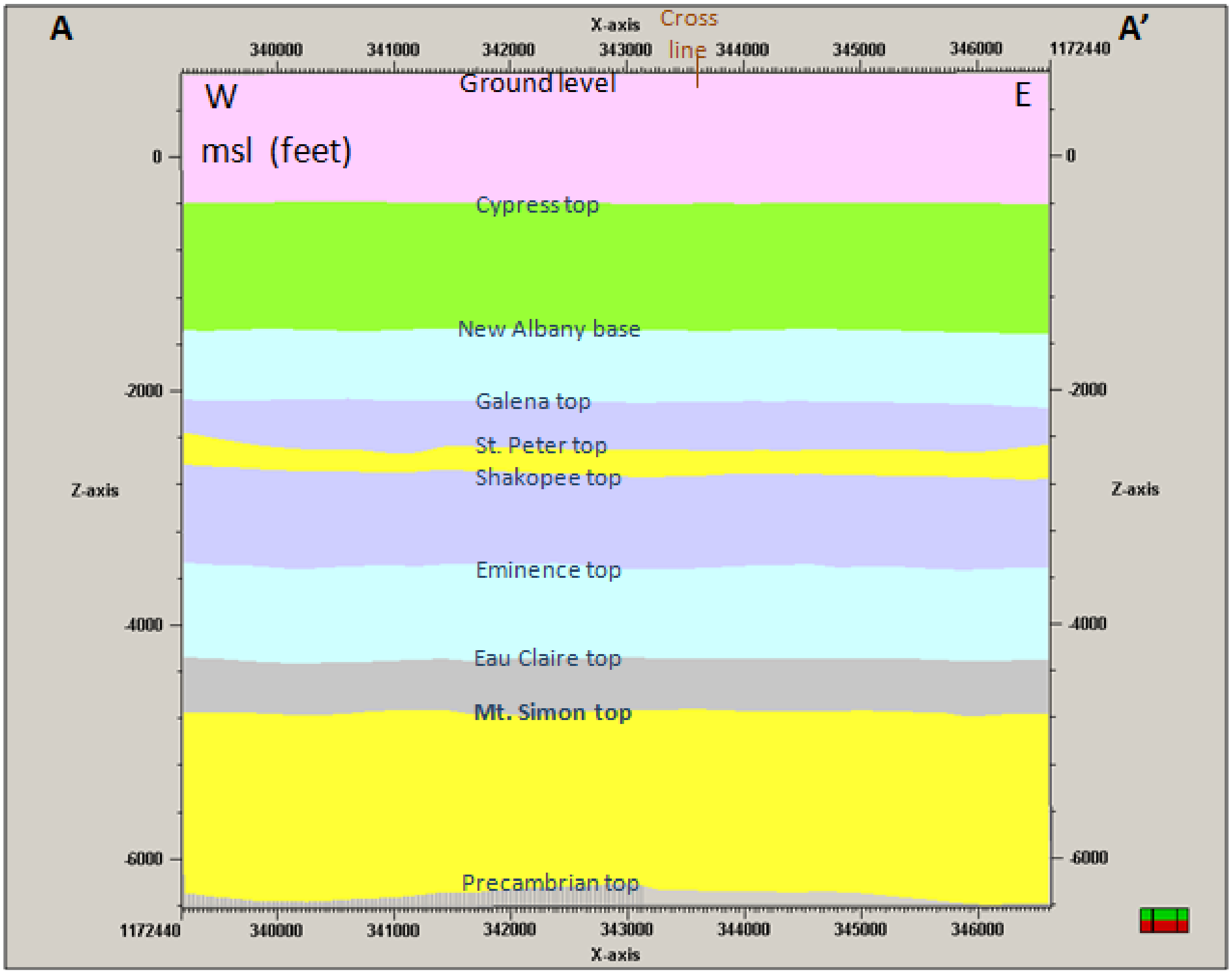


Figure 2 - 6 Cross section illustrating the geology along west (A) to east (A') direction

Cross section illustrating the geology along west (A) to east (A') direction (location given by Figure 2-5). Source: Smith, Schlumberger Carbon Services, 2011

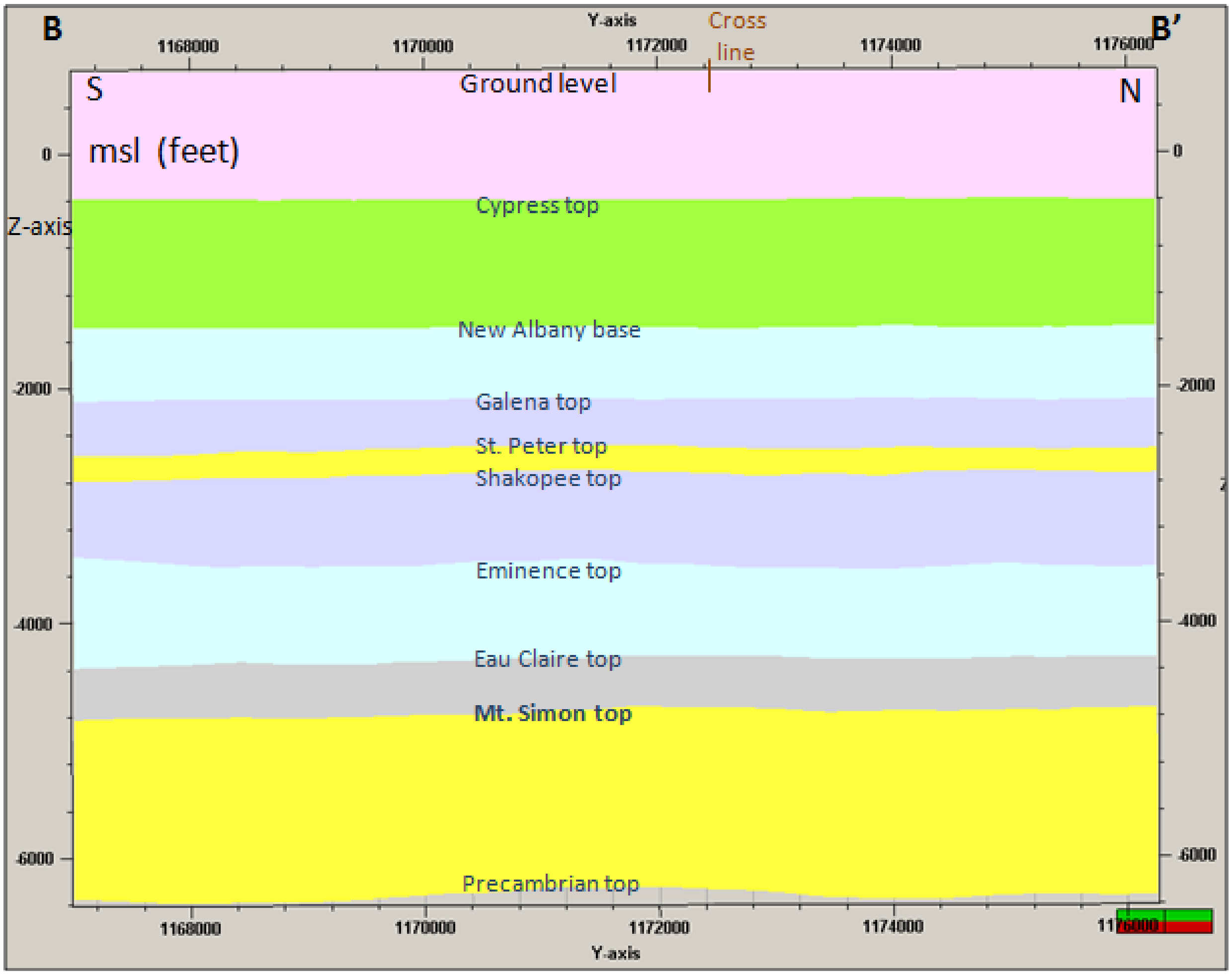


Figure 2 - 7 Cross section illustrating the geology along south (B) to north (B') direction

Cross section illustrating the geology along south (B) to north (B') direction (location given by Figure 2-5). Source: Smith, Schlumberger Carbon Services, 2011 .

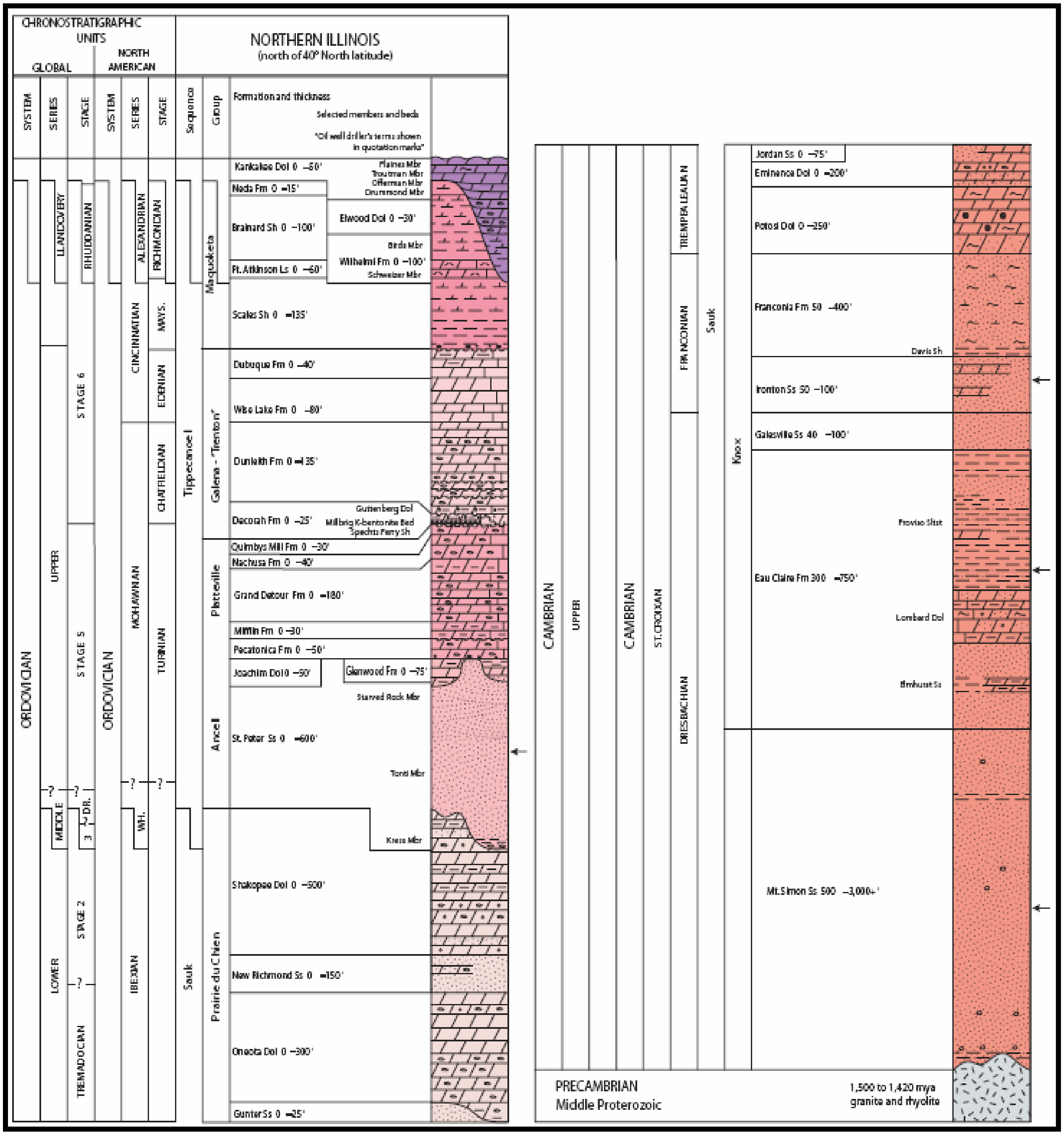


Figure 2 - 8 Stratigraphic column of Ordovician through Precambrian rocks in northern Illinois

Stratigraphic column of Ordovician through Precambrian rocks in northern Illinois (Kolata, 2005). Arrows point to the formations discussed in this UIC permit application. Dr. Darriwillian; Dol, dolomite; Fm, formation; Ls, limestone; MAYS., Maysvillian; Mbr, Member; Sh, shale; WH., Whiterockian; Mya, million years ago; Ss, sandstone; Silts, siltstone.

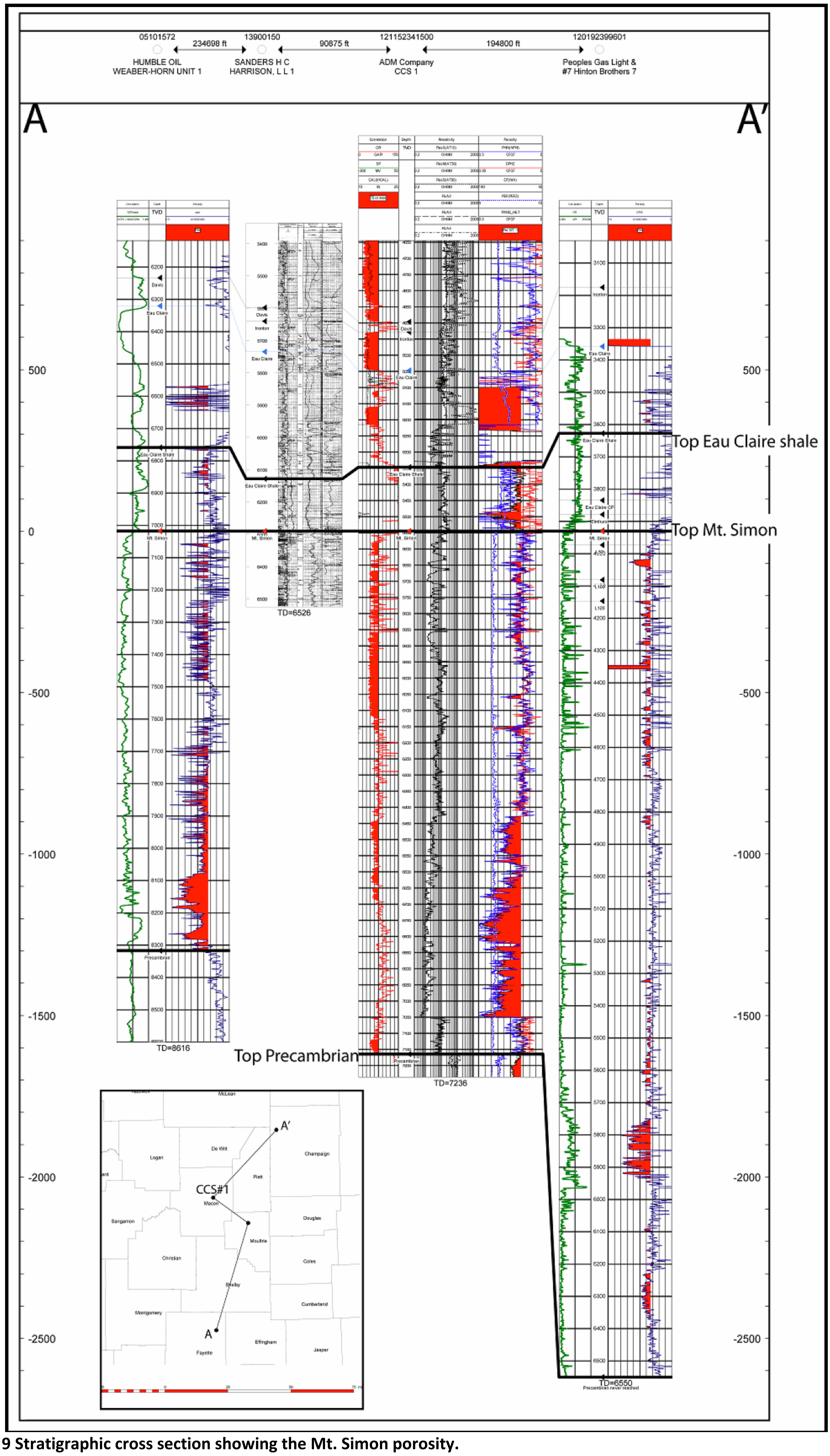


Figure 2 - 9 Stratigraphic cross section showing the Mt. Simon porosity.

Stratigraphic cross section through the Weaber Horn #1, Harrison #1, CCS #1 and the Hinton #7 wells showing the Mt. Simon porosity. The red colored zones have porosity greater than 10% (Frommelt, 2010).

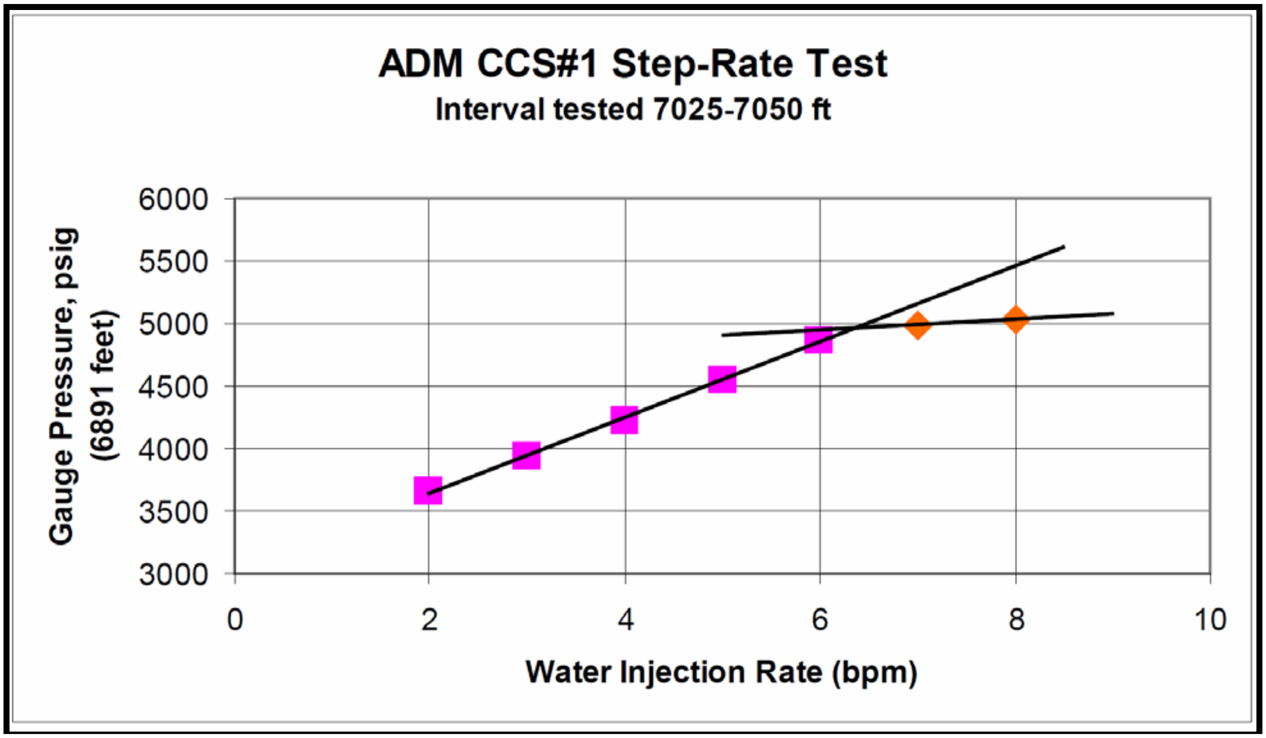


Figure 2 - 10 CCS #1 step-rate test

IBDP CCS #1 step-rate test with fracture propagation pressure of 4966 psig estimated from the intersection of the two lines. The first line (2-6 bpm) represents radial flow of the Mt. Simon; the second line 7-8 bpm represents flow into the Mt. Simon after a fracture has propagated. The perforated interval was 7,025 to 7,050 feet during this step-rate test. These results correspond to a fracture gradient of 0.715 psi/ft. Source: Frommelt, 2010.

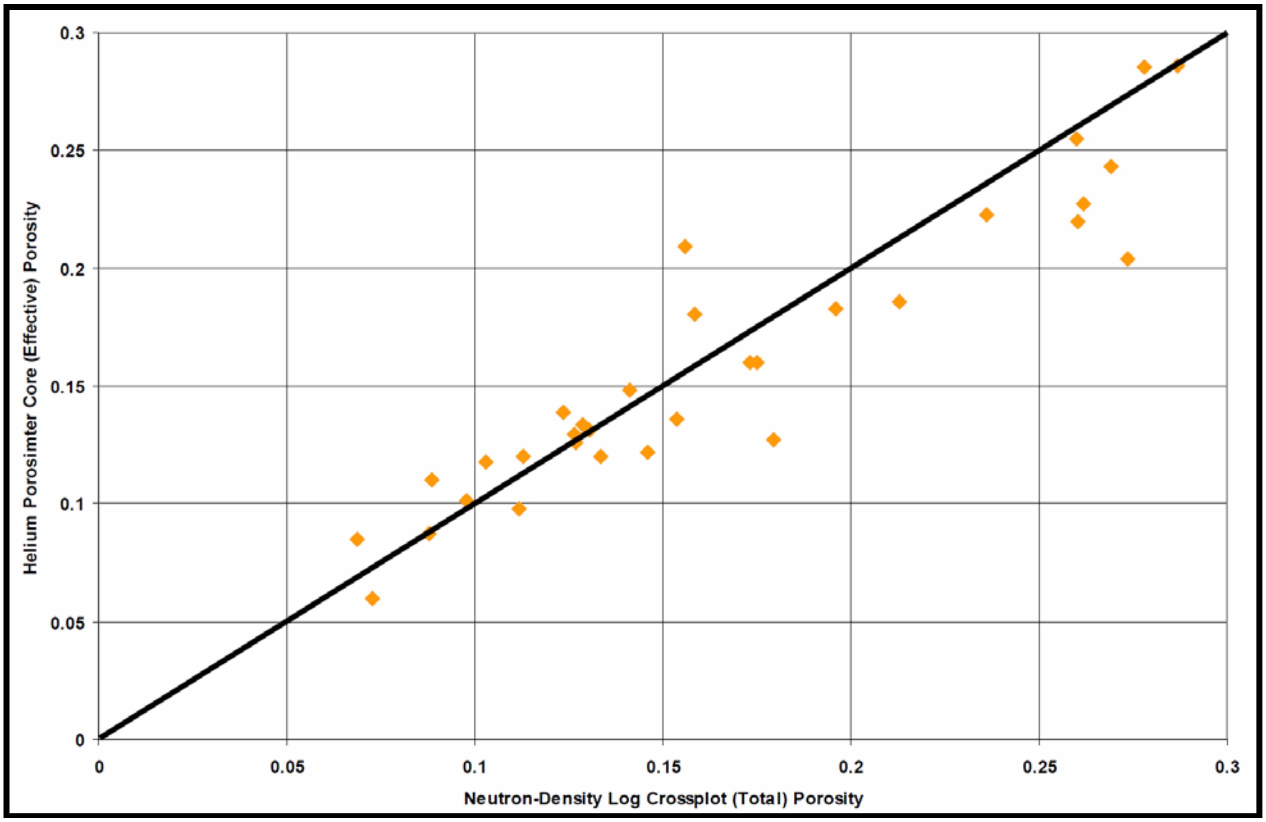


Figure 2 - 11 Crossplot of helium porosimeter and neutron-density data for CCS #1.

The bold line through the data is the unit slope, showing very good correlation between the two types of porosity data. For the porosity data from the rotary sidewall core plugs and the neutron-density crossplot porosity at the interval of the core plug, the porosity compares relatively well such that total and effective porosity are very similar. Source: Frommelt, 2010.

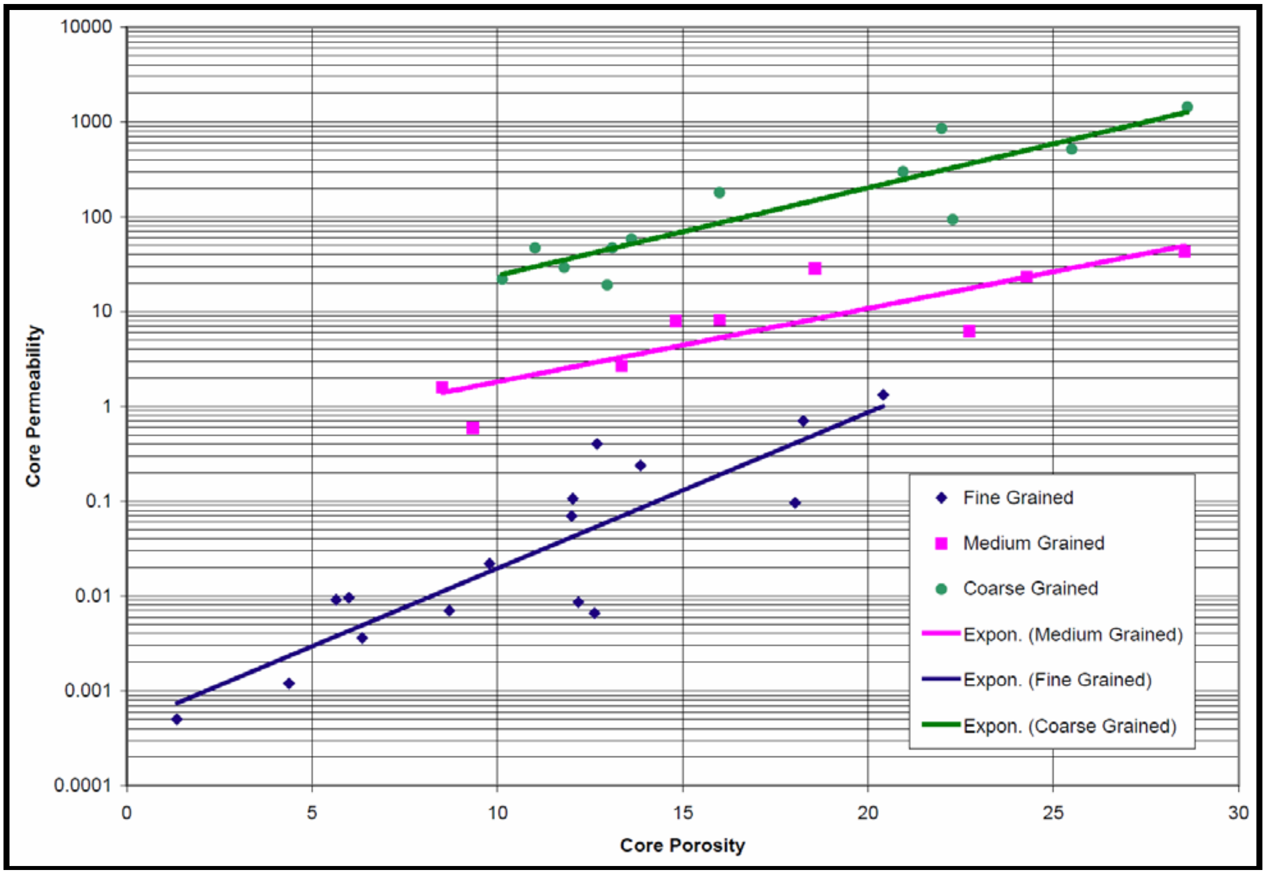


Figure 2 - 12 Crossplot of core permeability versus core porosity for CCS #1.

Transforms were developed for three different grain sizes—fine grained, medium grained and coarse grained sandstone. Source: Frommelt, 2010.

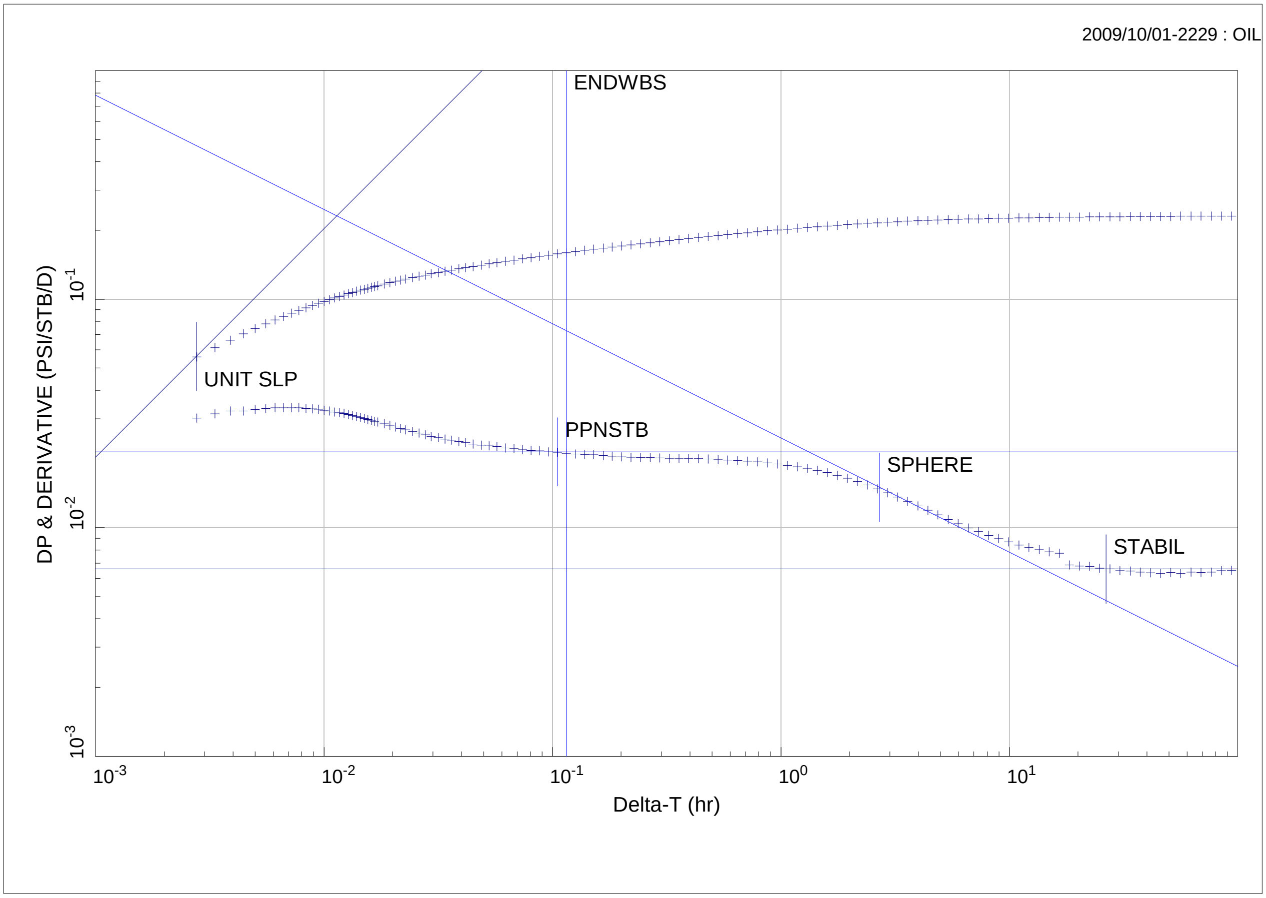


Figure 2 - 13 Qualitative derivative analyses of final pressure falloff test.

Qualitative derivative analyses of final pressure falloff test conducted in CCS #1. Radial pressure response is indicated by a horizontal derivative trend. Two periods were measured during this test between 0.1 and 1 hours (PPNSTB) and 20 to 100 hours (STABIL). The first period corresponds to radial flow across the perforated interval; the second period corresponds to the larger thickness that would be between two much lower permeability sub-units e.g, the less permeable arkose-rich interval at the base and a tighter interval above the perforated interval. The transition between the two radial responses (SPHERE) is a spherical flow period that is influenced by vertical permeability (or kv/kh). (The unit slope (UNIT SLP) indicating wellbore storage, identifies the end of wellbore storage influenced pressure data (ENDWBS) or pressure data that can be analyzed from reservoir properties.). Source: Frommelt, 2010.

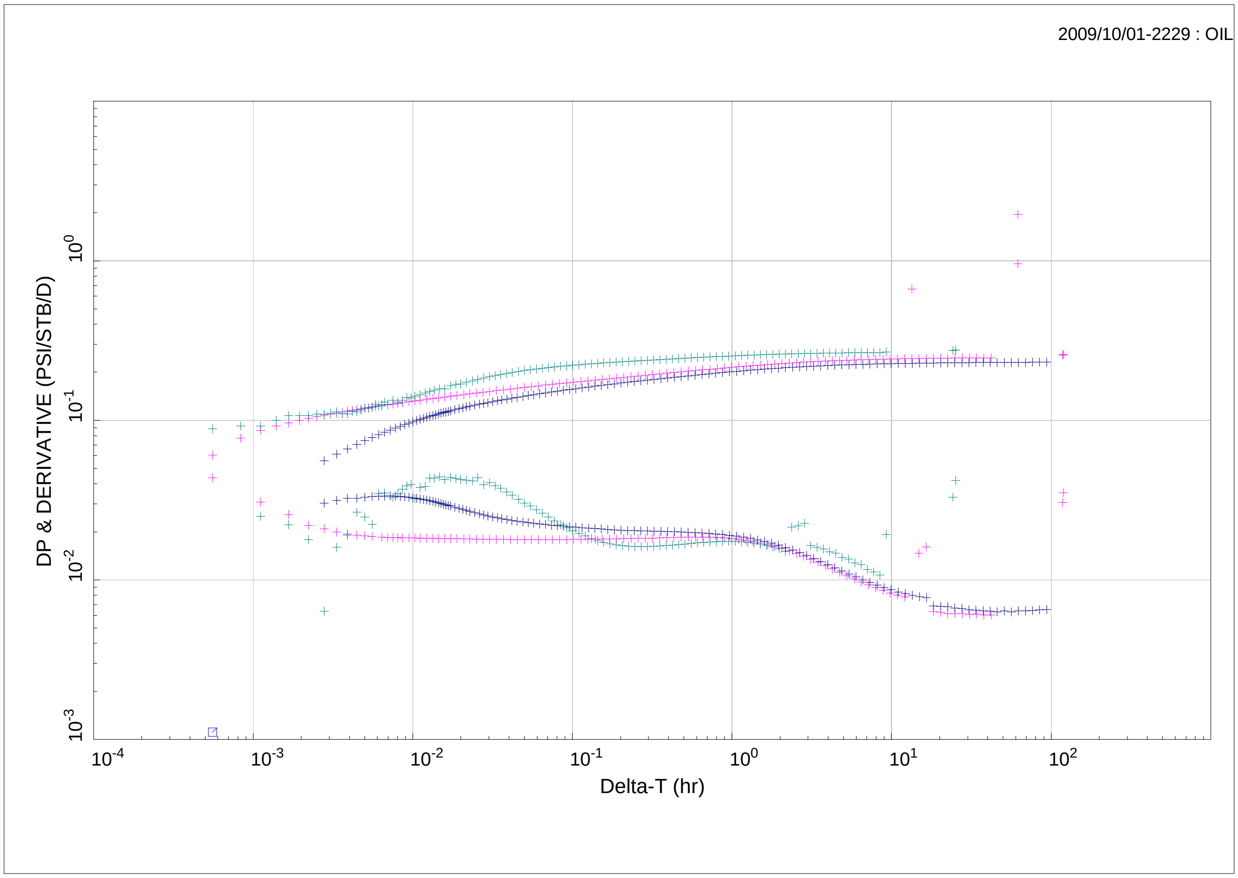
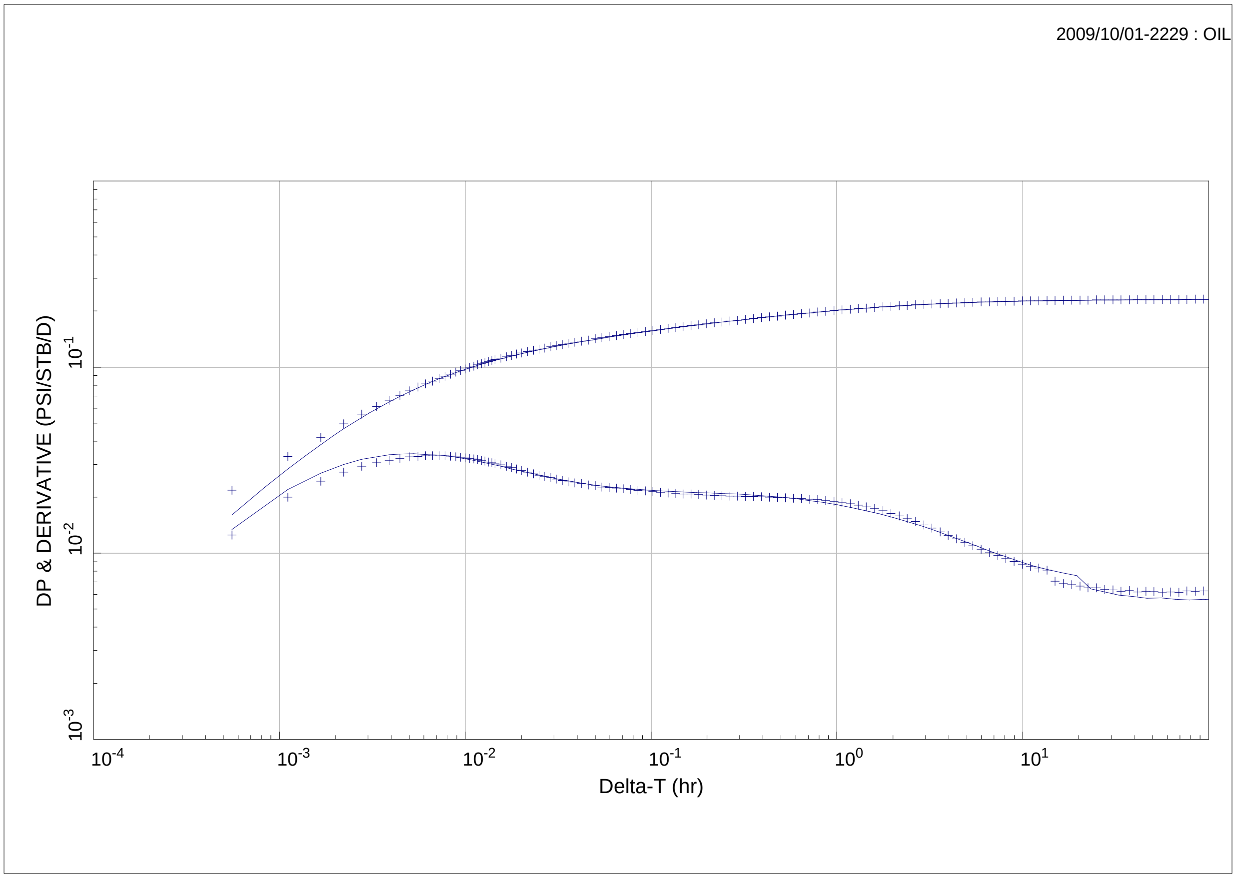


Figure 2 - 14 Overlay of pressure derivative of the three pressure falloff tests

Overlay of pressure derivative of the three pressure falloff tests conducted in CCS #1. The Green curve (upper pressure curve and bell shaped derivative) is the first falloff which had perforated interval of 7025-7050 ft MD. The pink (lower derivative curve) is the second falloff in the same perforated interval which had a modest acid treatment prior to the falloff. The dark blue (lower pressure curve middle derivative curve) was the third falloff tests for the perforated intervals of 6982-7012 and 7025-7050 ft MD and a second acid treatment over both perforated intervals. The difference between the green curve and the pink curve in the first 6 minutes is a result of the improvement to flow due to the acid treatment. The upper curves show the pressure difference and the lower curves show the derivative. Source: Frommelt, 2010.



Partial Penetration Well

** Simulation Data **			Type-Curve Model Static-Data		
well. storage	=	0.0011457 BBLS/PSI	Perf. Interval	=	25.0 FEET
Skin(mech.)	=	-0.85807			
permeability	=	184.58 MD	Static-Data and Constants		
Kv/Kh	=	0.013260	Volume-Factor	=	1.000 vol/vol
Eff. Thickness	=	75.000 FEET	Thickness	=	75.00 FEET
Zp/Heff	=	0.83330	Viscosity	=	1.300 CP
Skin(Global)	=	10.301	Total Compress	=	.1800E-04 1/PSI
Perm-Thickness	=	13843. MD-FEET	Rate	=	-6100. STB/D

Figure 2 - 15 Simulation history matching of the of final pressure falloff test

Nonlinear regression, or simulation history matching, of the of final pressure falloff test conducted in CCS #1. Test data shown as + symbols and simulated data shown as line. The upper curve is the pressure difference and the lower curve is the derivative. Source: Frommelt, 2010.

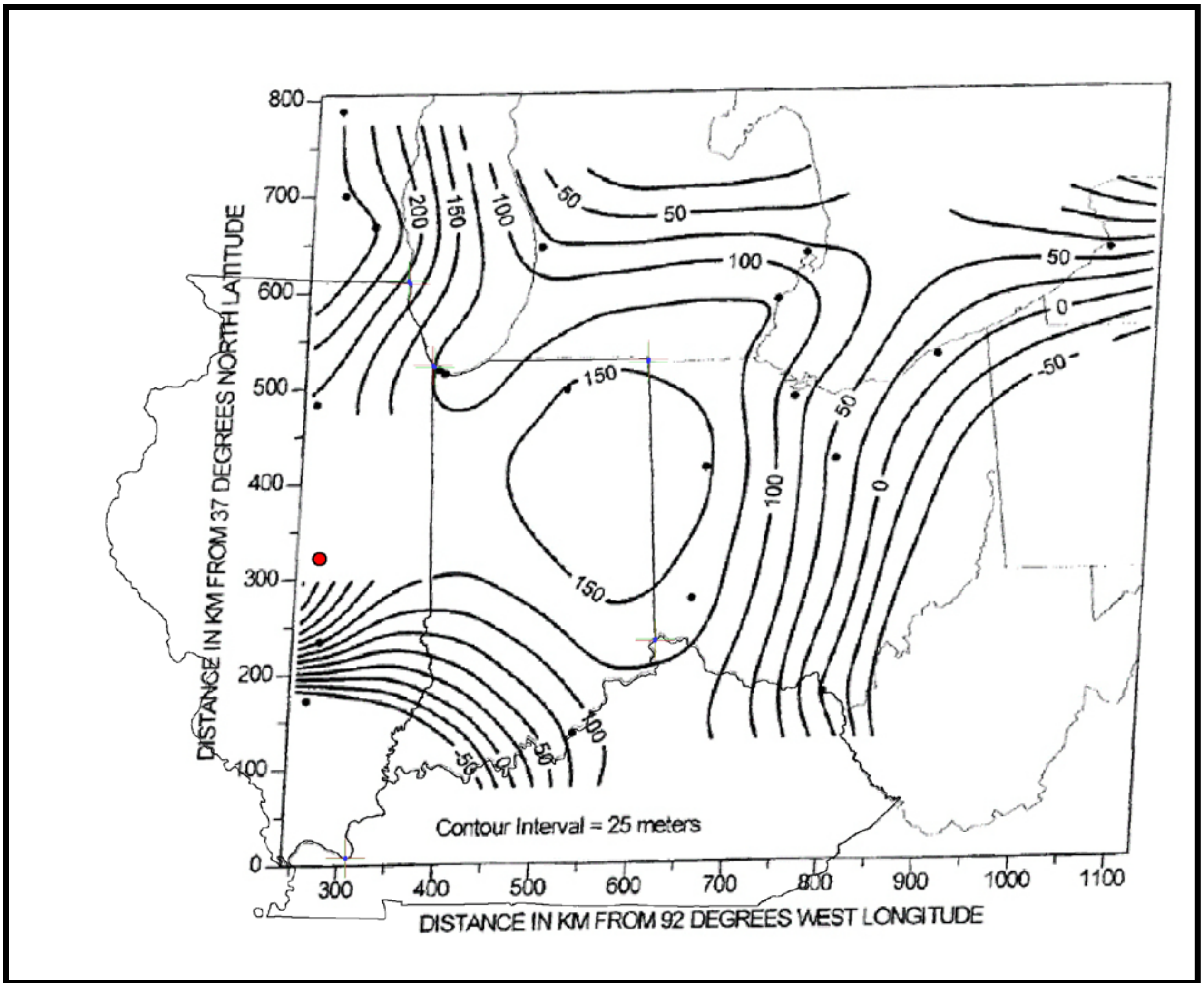


Figure 2 - 16 Observed head in the Mt. Simon sandstone.

Groundwater flows from areas of higher head to lower head, along lines perpendicular to the head lines. Contour interval = 25 m. (modified from Gupta and Bair, 1997). At the CCS #1 well (red dot), the potentiometric surface was calculated to be 76 m above mean sea level.

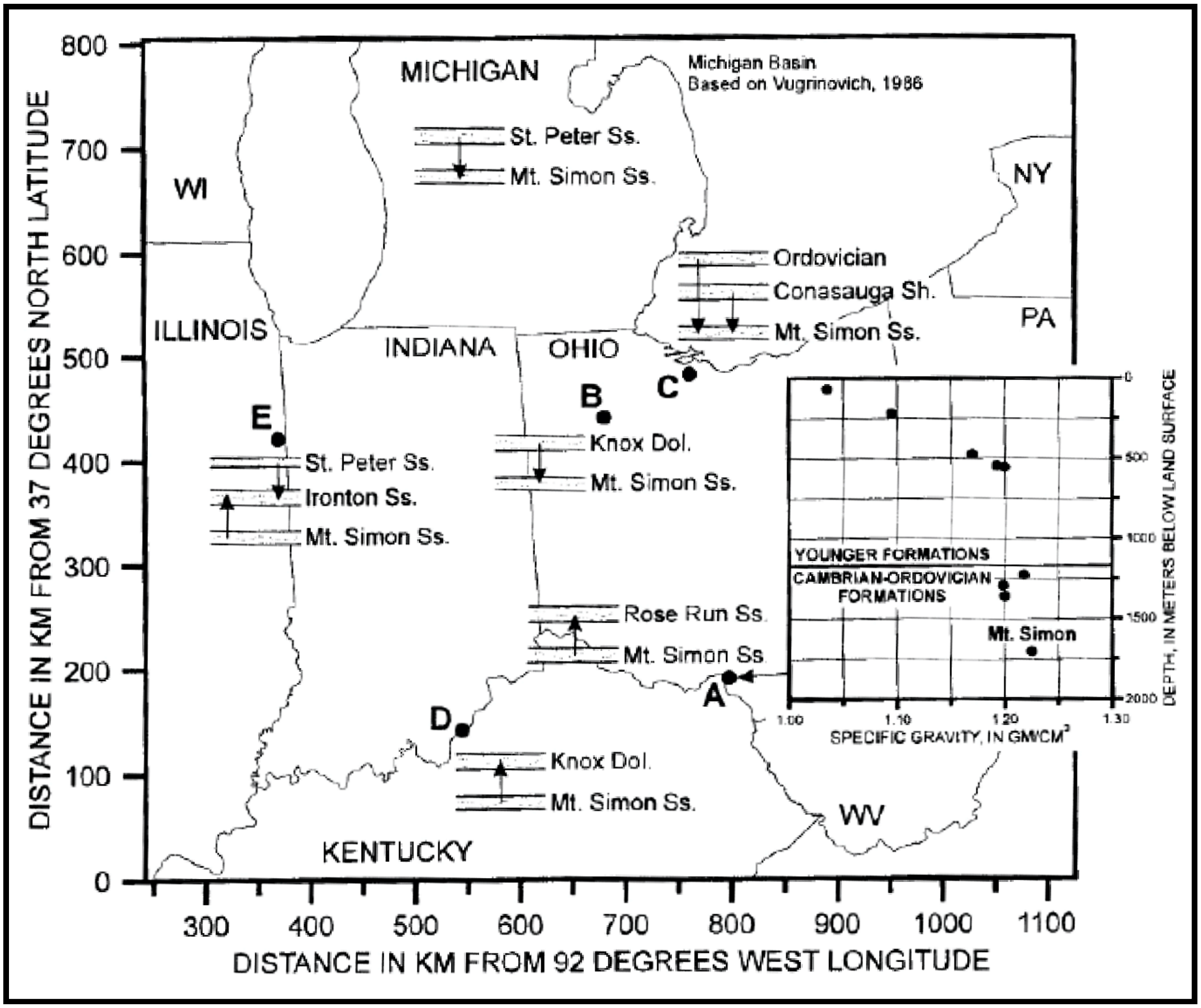


Figure 2 - 17 Observed vertical flow components in the Mt. Simon Sandstone

Observed vertical flow components in the Mt. Simon Sandstone around the Upper Midwest with the Michigan Basin based on Vugrinovich (1986), (from Gupta and Bair, 1997).

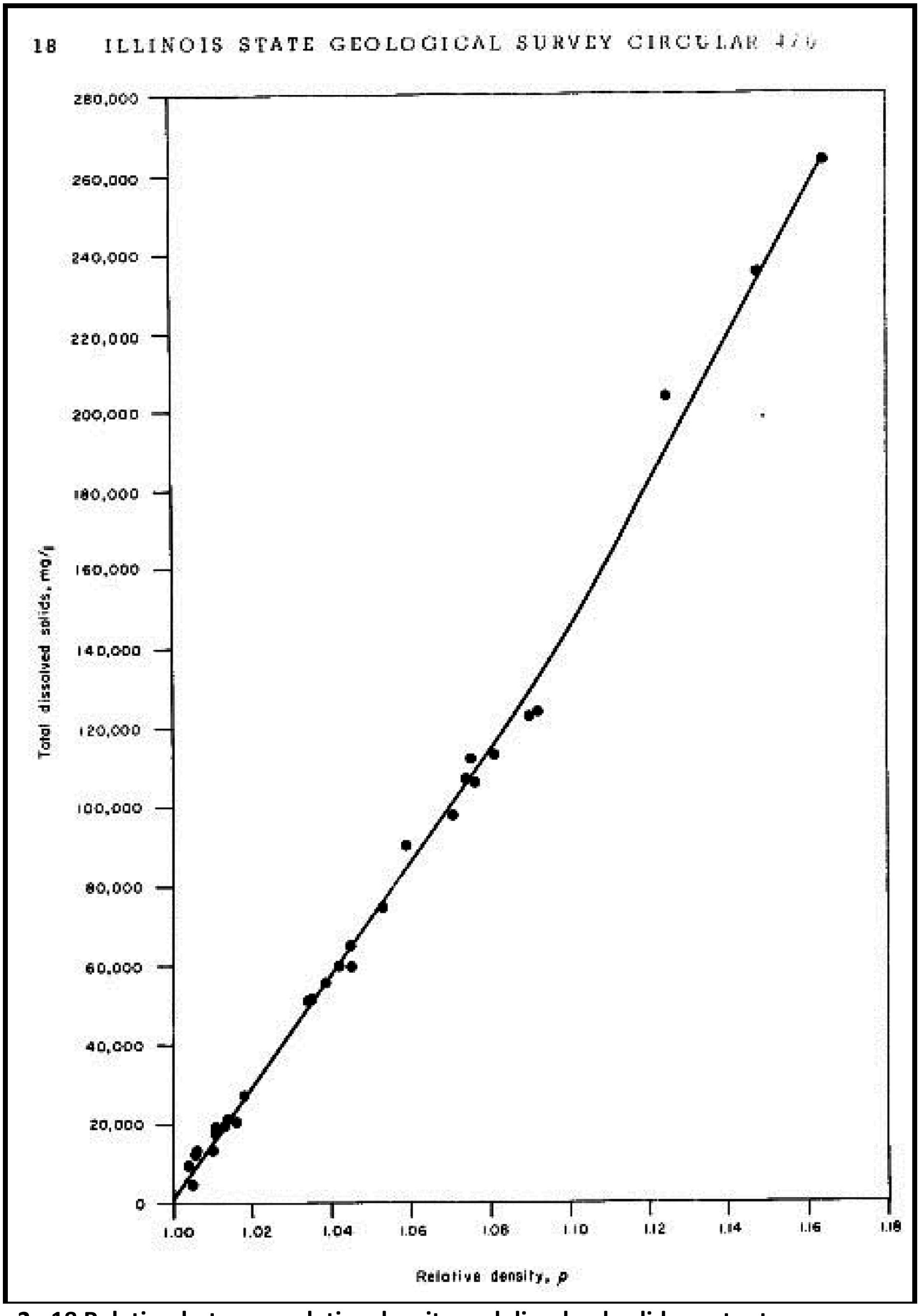


Figure 2 - 18 Relation between relative density and dissolved solids content

Relation between relative density and dissolved solids content of brines in deep aquifers of the Illinois Basin. Source: Bond (1972).

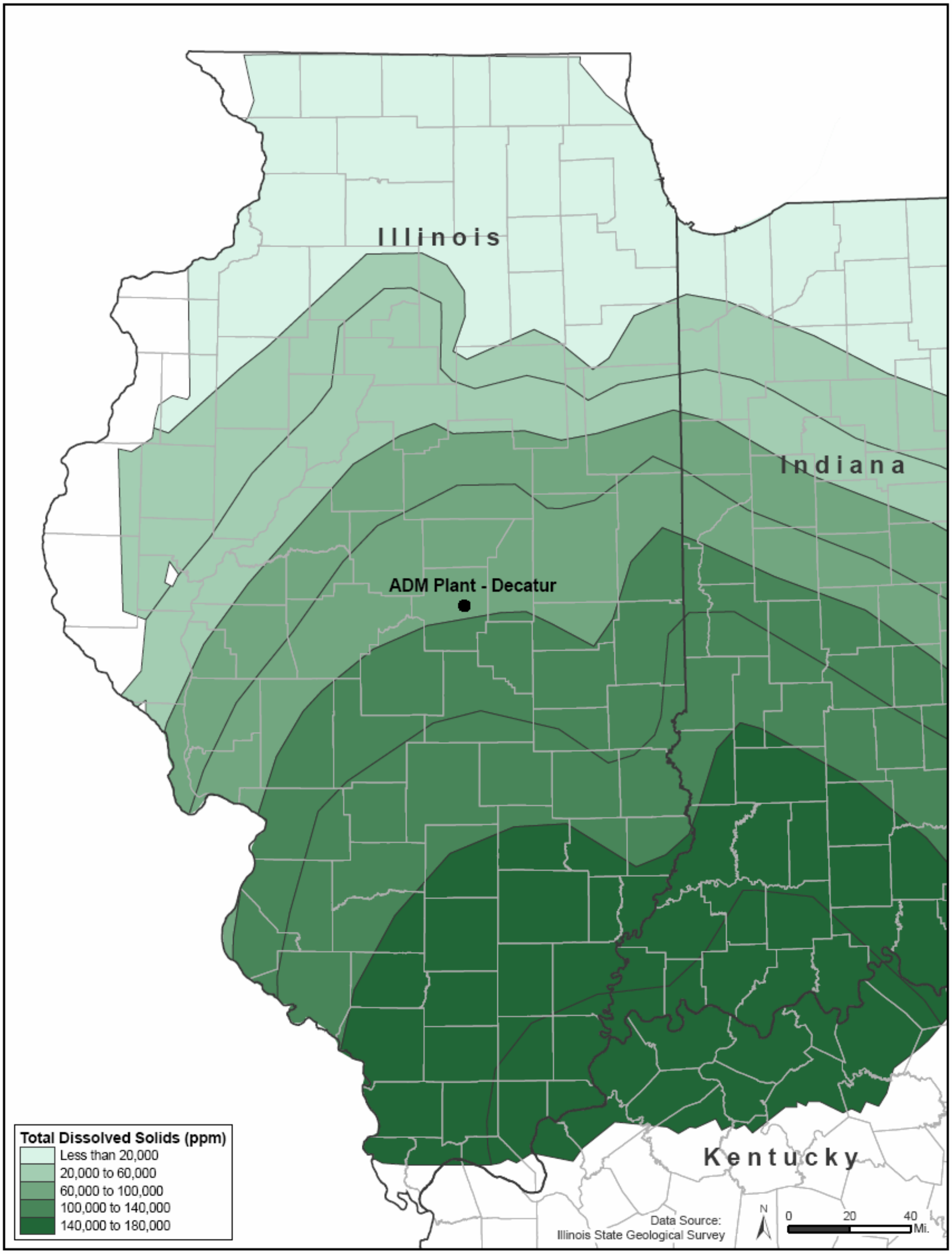


Figure 2 - 19 Total dissolved solids (TDS) within the formation water of the Mt. Simon Reservoir

Source: Modified from Finley, 2005.

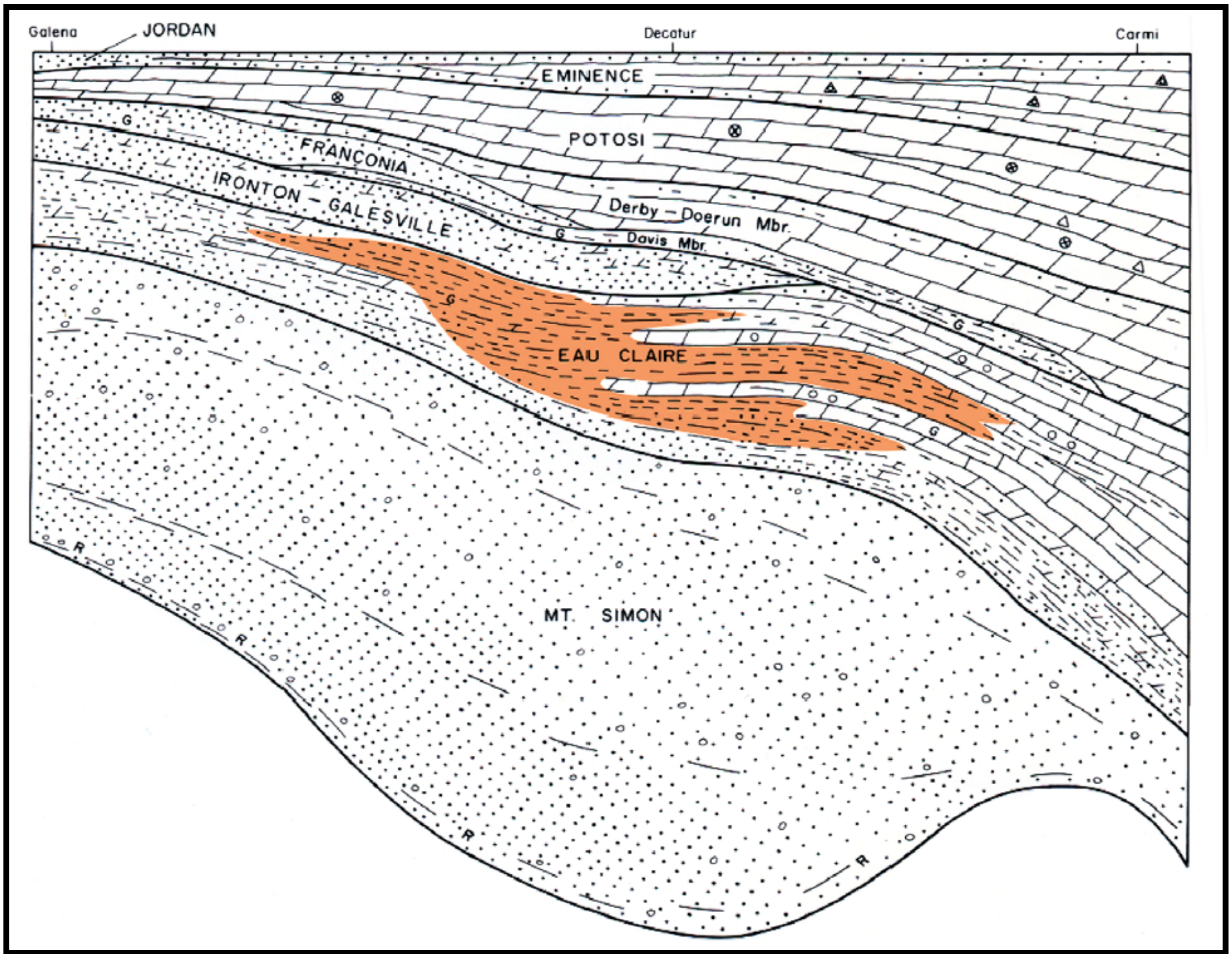


Figure 2 - 20 Cross section of the Cambrian System

Diagrammatic cross section of the Cambrian System from northwestern to southeastern Illinois. The orange color shows the areas where the Eau Claire formation is primarily shale and should be a good seal. Uncolored areas may behave as seals, but there is an enhanced risk for leakage because of fracturing (modified after Willman et. al., 1975).

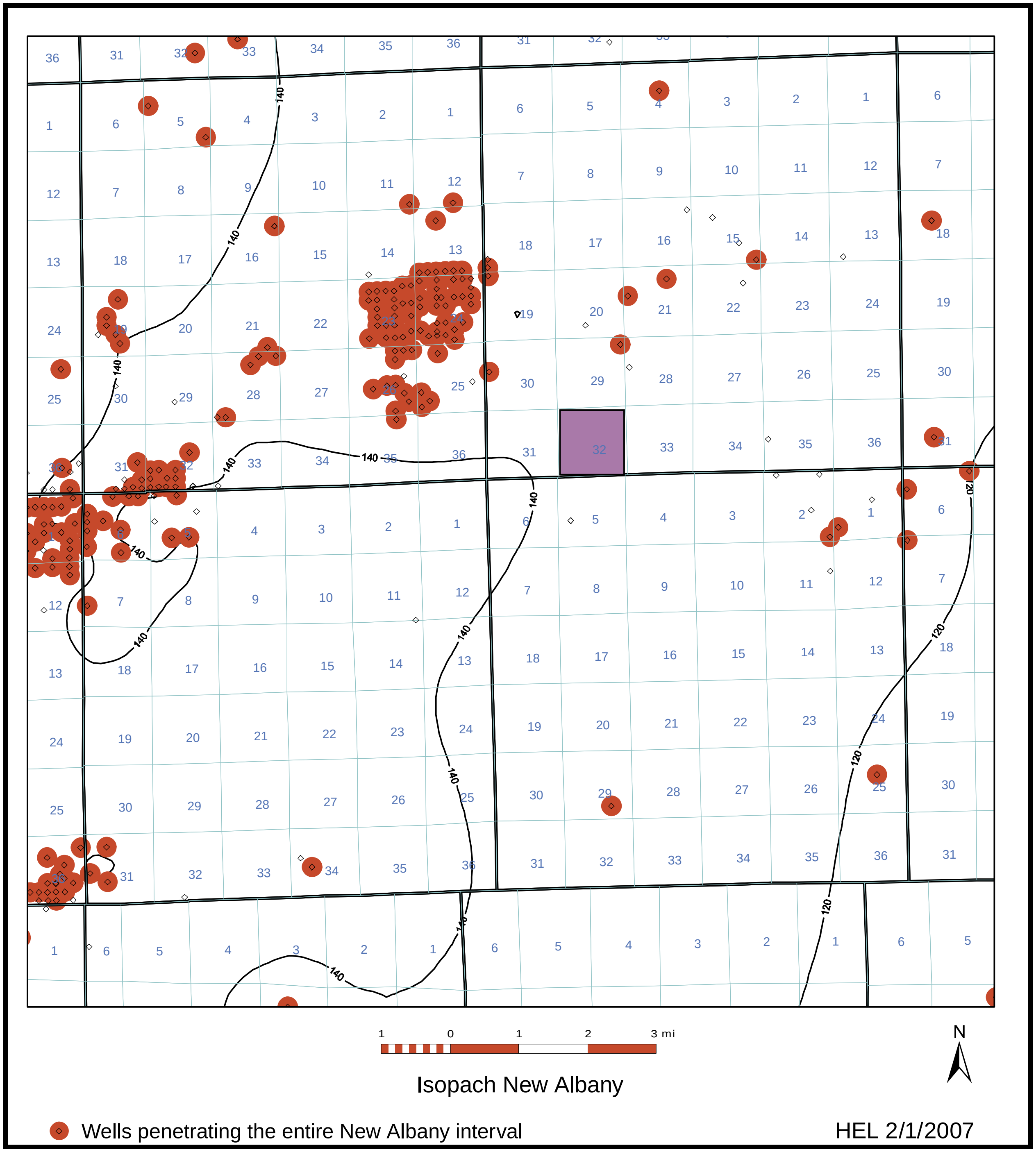


Figure 2 - 21 Thickness (feet) of the New Albany Shale.

Proposed injection well is near the center of Section 32 (shaded purple). Source: Leetaru, 2007.

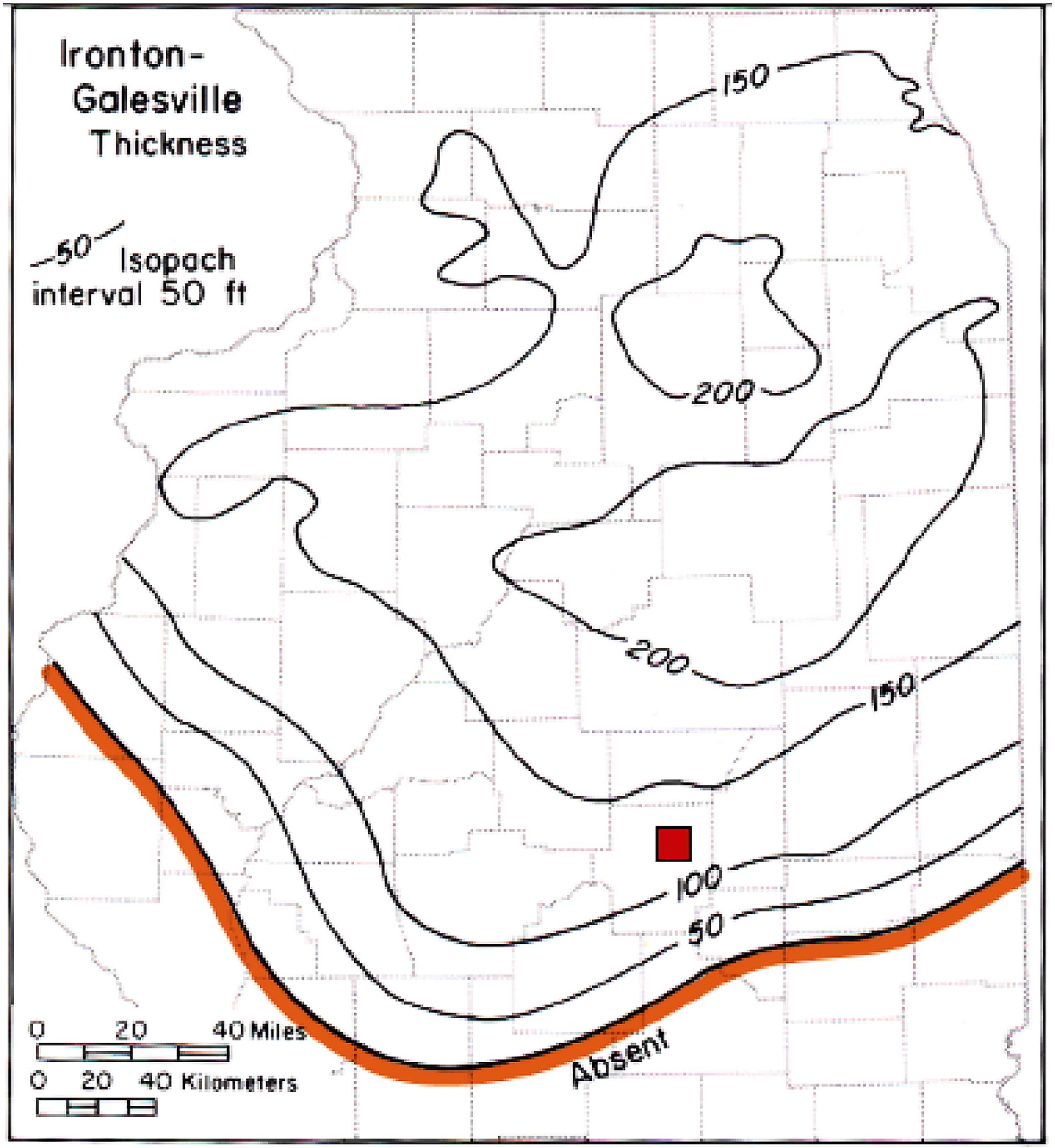


Figure 2 - 22 Isopach of the Ironton-Galesville Sandstone in Illinois.

The orange line signifies the southern limit of the formation. There are no sandstone facies south of this line. (Willman, et al, 1975). The approximate site location is denoted by the red square.

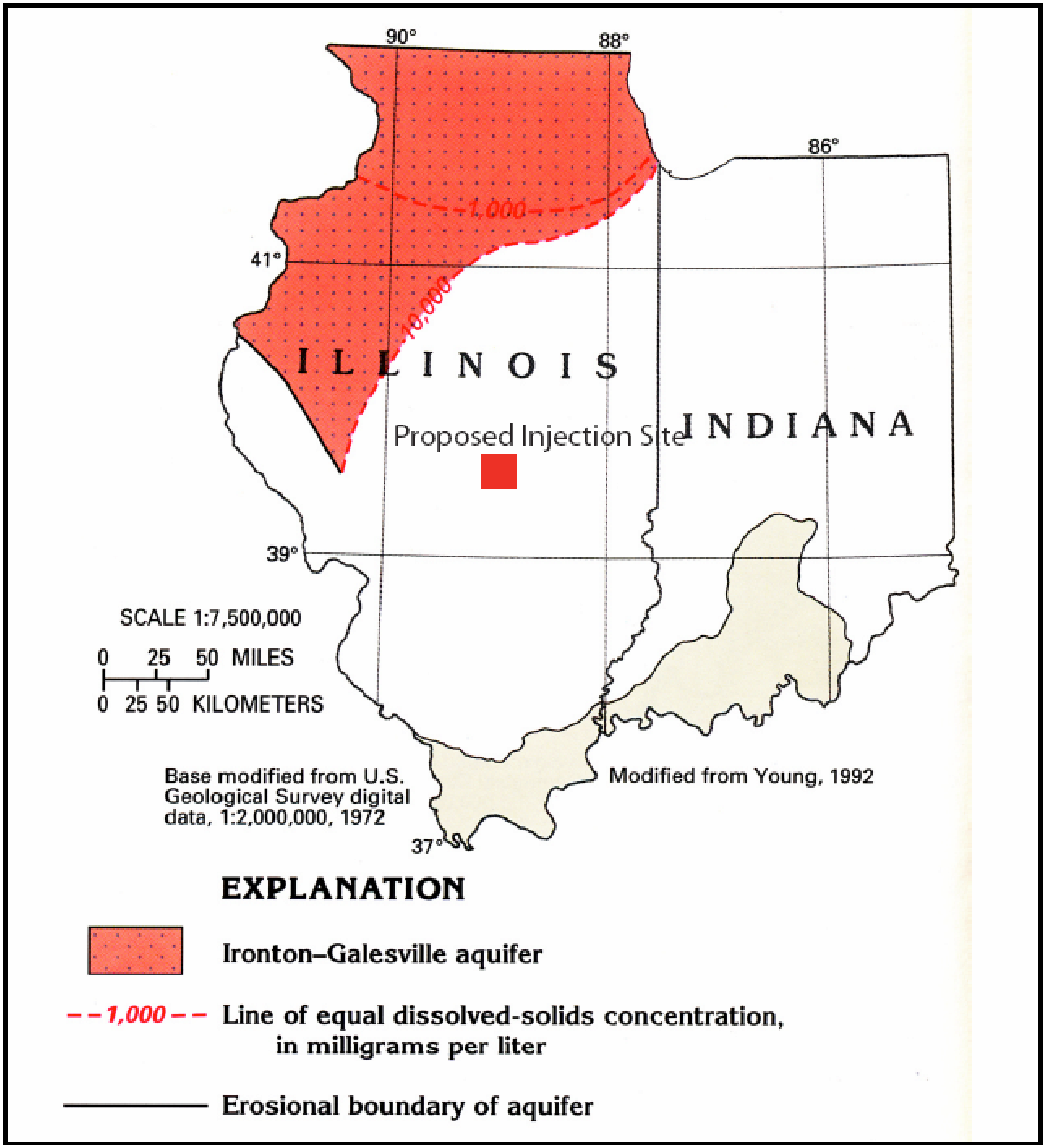


Figure 2 - 23 Regional map showing limits of fresh water in the Ironton-Galesville Sandstone. Proposed injection site should not encounter freshwater when drilling this formation. Source: Loyd, O,B. and W.L. Lyke, 1995, Ground Water Atlas of the United States, Segment 10: United States Geological Survey, 30 p. The red square denotes the relative location of the proposed injection site.

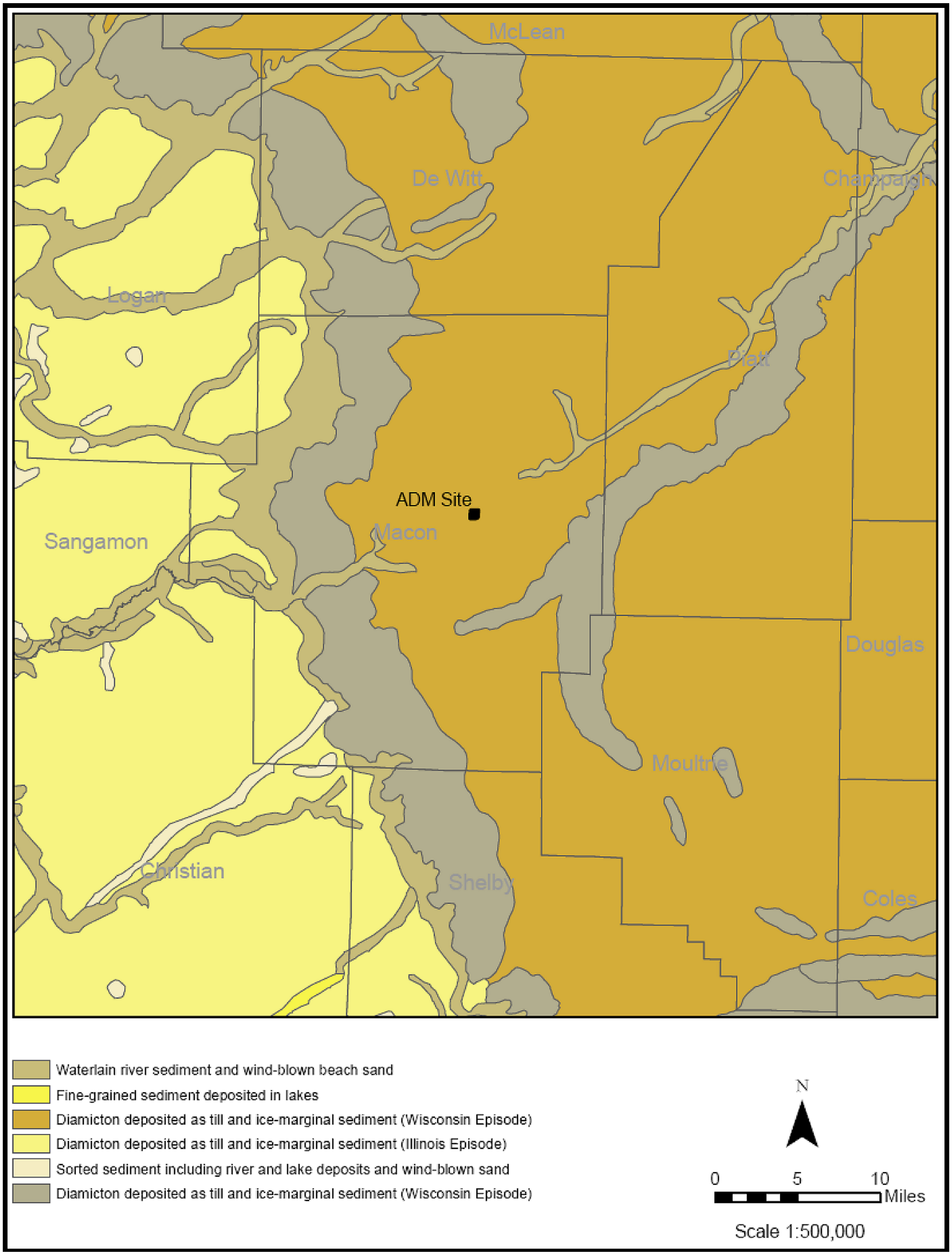


Figure 2 - 24 Regional Quaternary deposits near the Injection Site, Decatur, IL.

Source: ISGS Quarternary Deposits GIS Dataset, 1996.

http://www.isgs.illinois.edu/nsdihome/webdocs/st-geolq.html

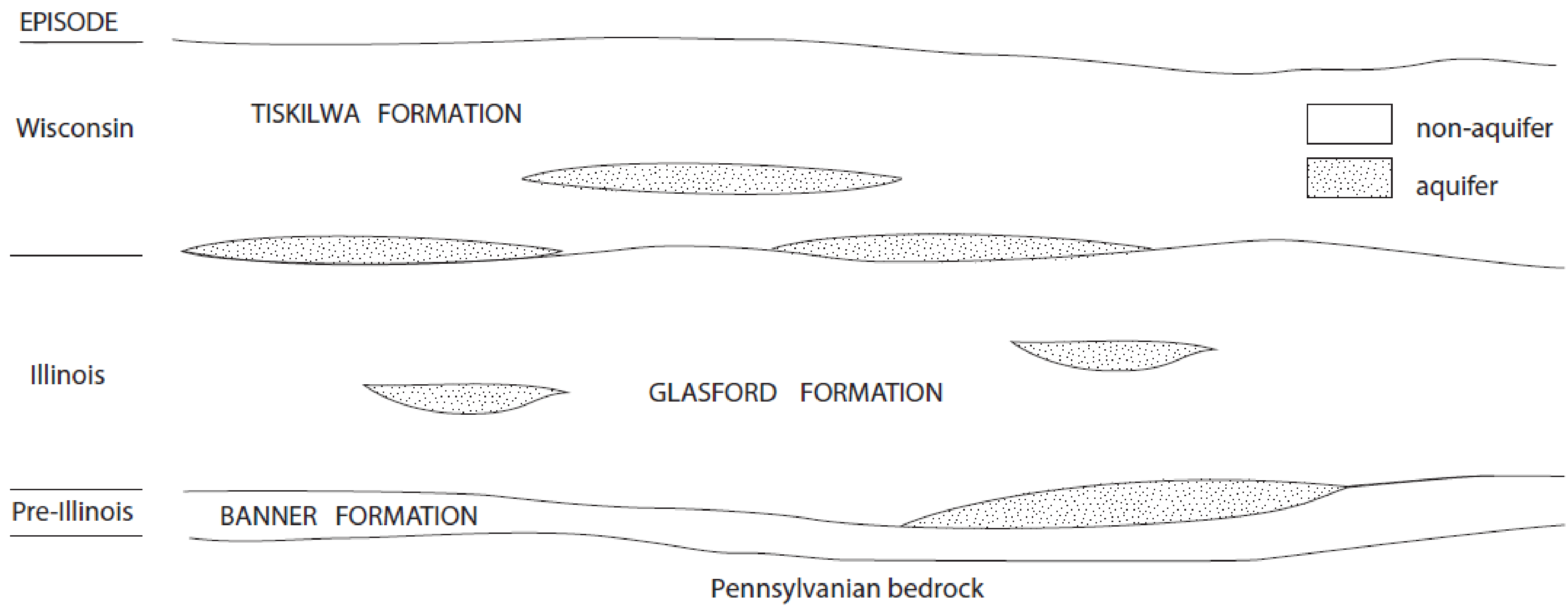


Figure 2 - 25 Vertical sequence of aquifers within the Quaternary sediments in Macon County

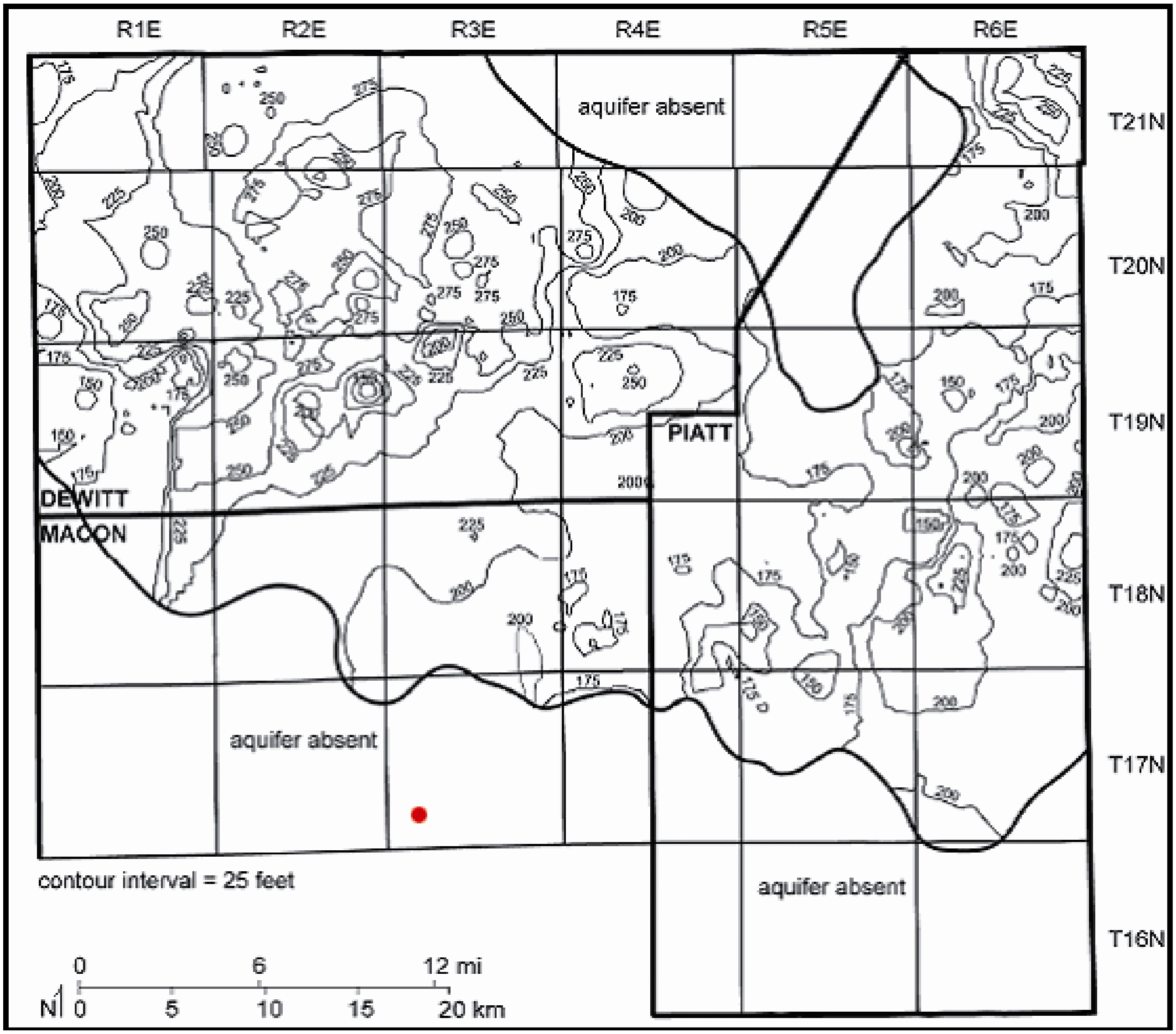


Figure 2 - 26 Depth to the top of the Mahomet aquifer

Proposed injection well location in red. (Larson et al., 2003)

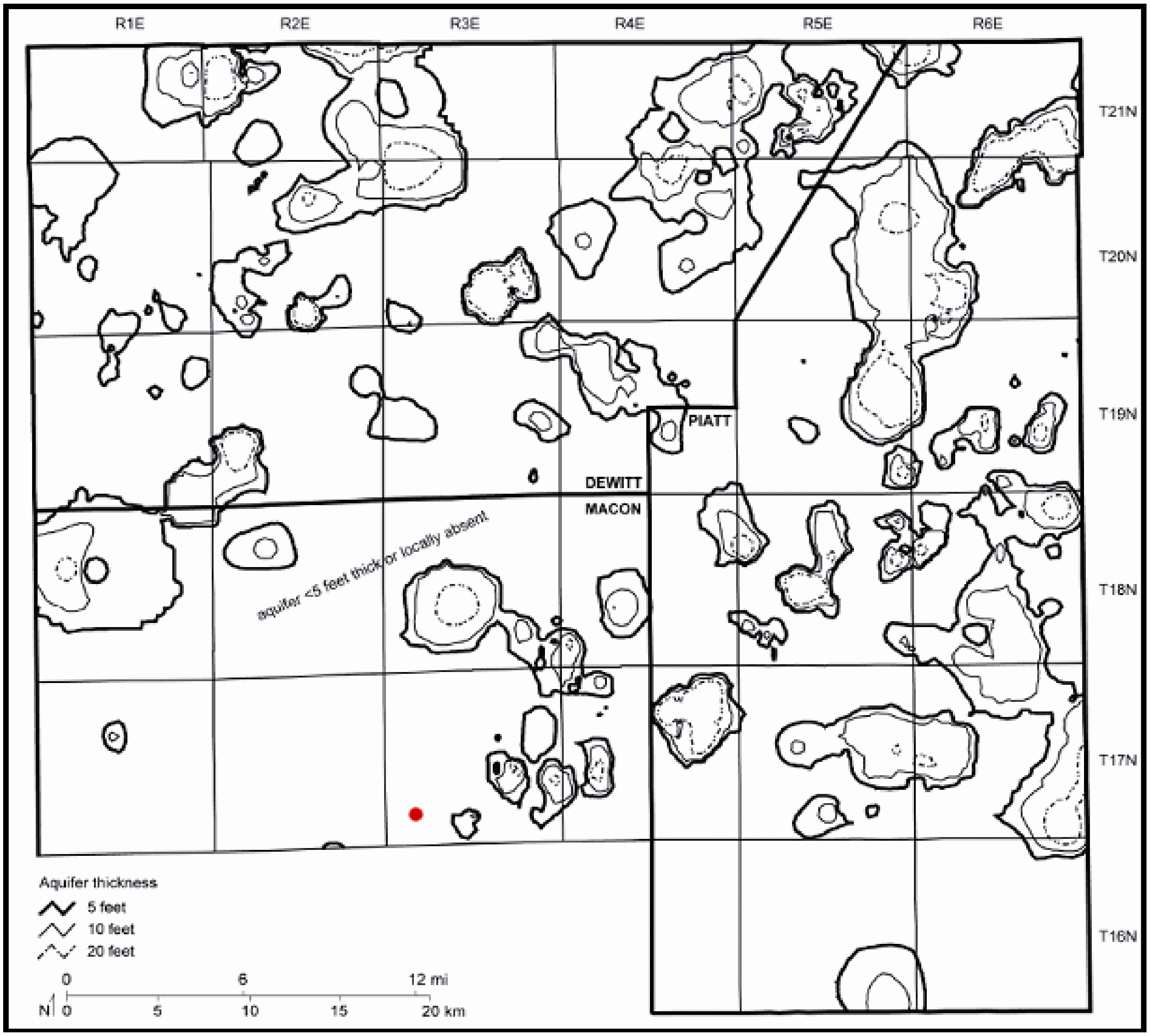


Figure 2 - 27 Thickness of the upper Banner aquifer

Proposed injection well location in red. (Larson et al., 2003)

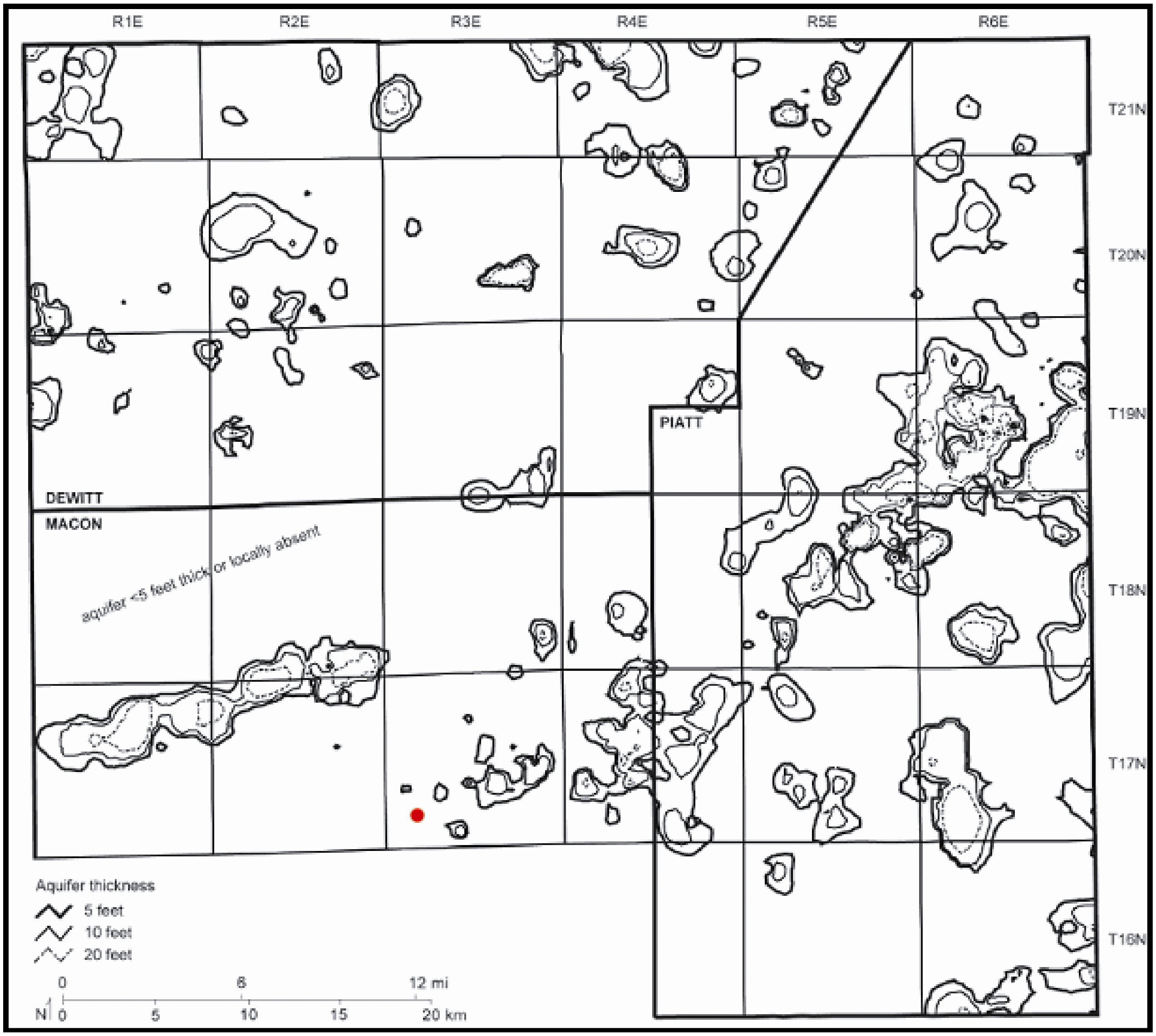


Figure 2 - 28 Thickness of the lower Glasford aquifer

Proposed injection well location in red. (Larson et al., 2003)

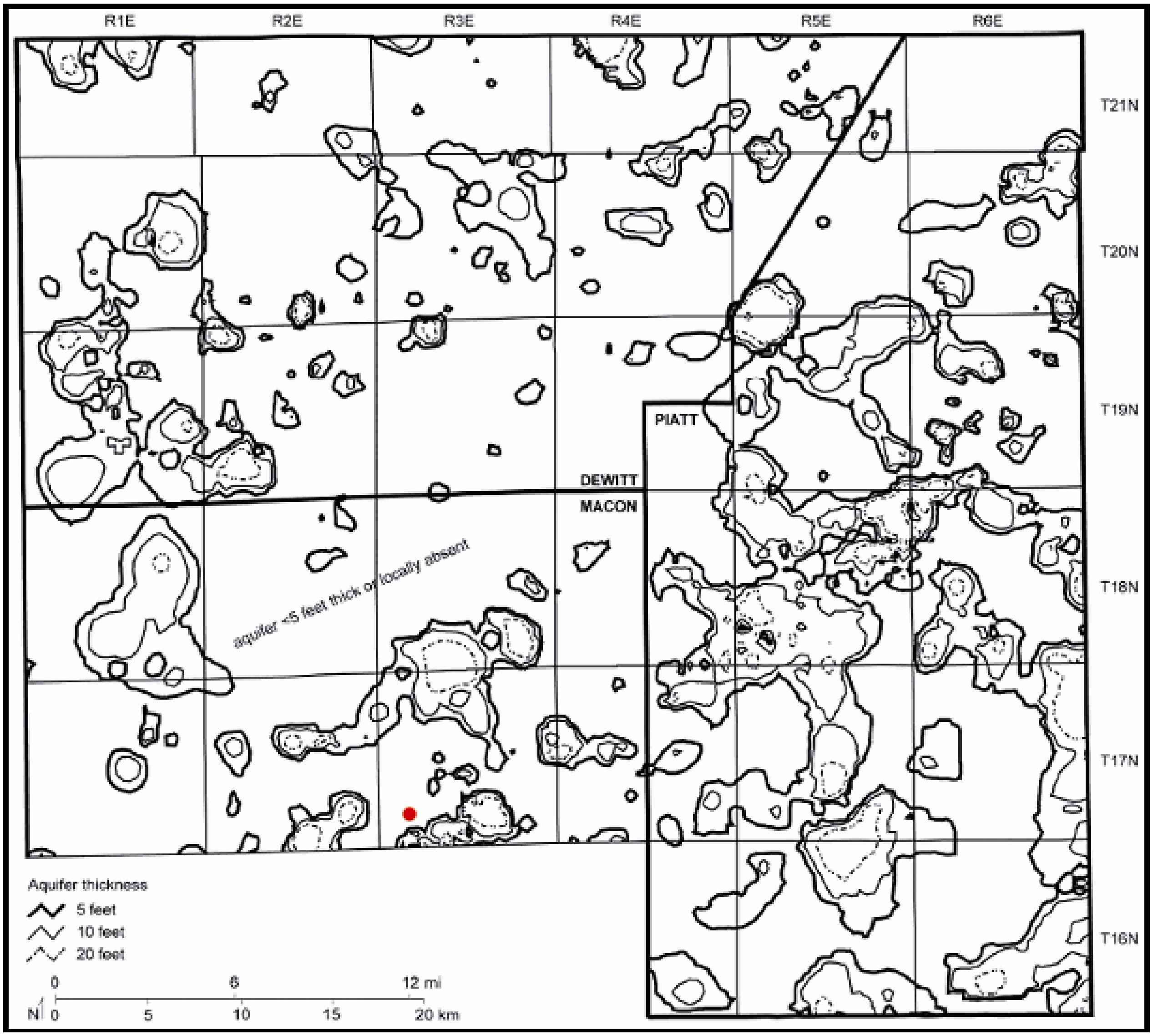


Figure 2 - 29 Thickness of the shallow sand aquifer.

Proposed injection well location in red. (Larson et al., 2003)

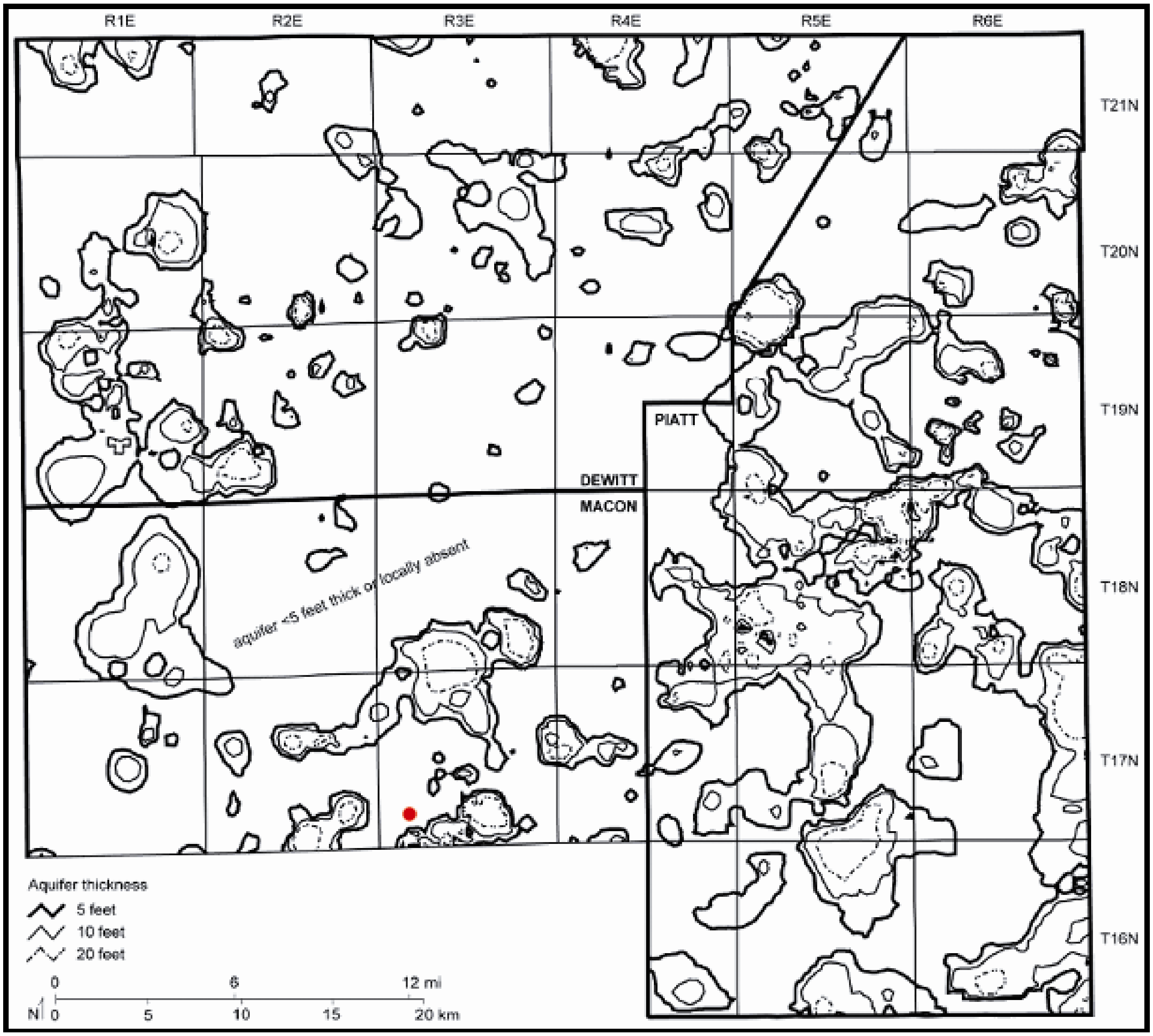


Figure 2 - 30 Thickness of the upper Glasford aquifer

Proposed injection well location in red. (Larson et al., 2003)

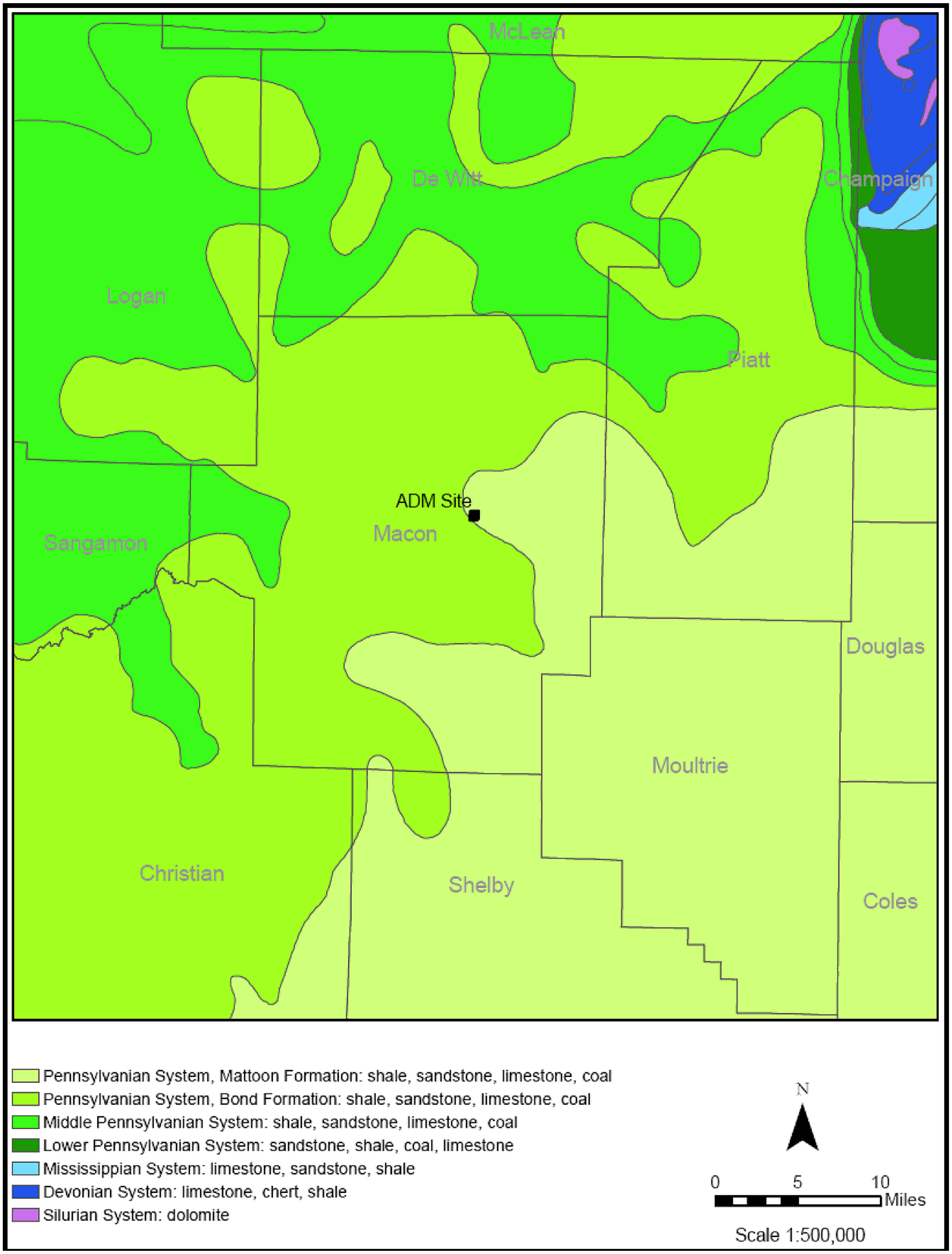


Figure 2 - 31 Regional bedrock geology near the Injection Site, Decatur, IL.

Figure 2-31: Source: ISGS Bedrock Geology GIS Dataset, 2005, http://www.isgs.illinois.edu/nsdihome/webdocs/st-geolb.html

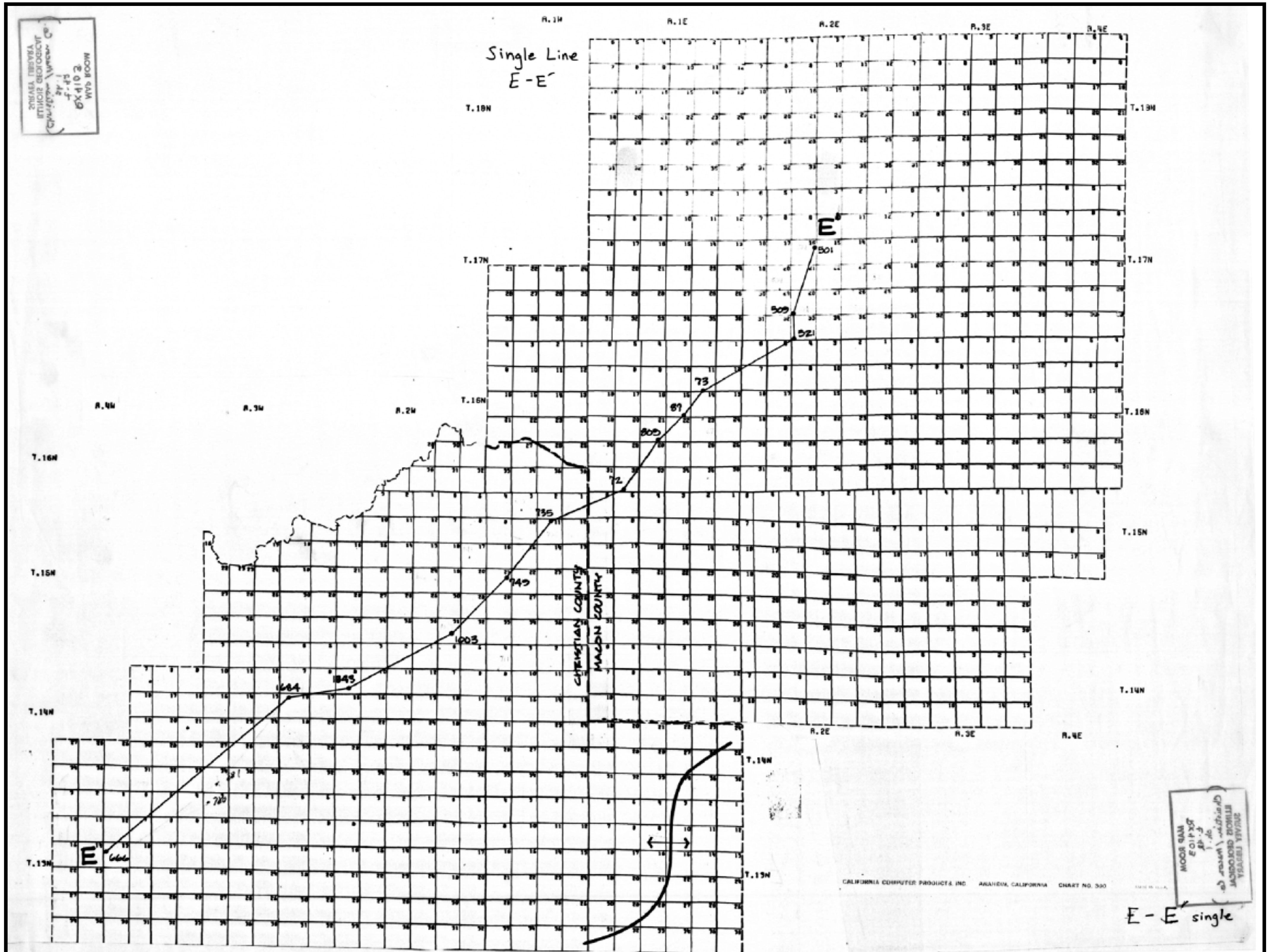


Figure 2 - 32 Map showing cross-section E-E' showing the depth to USDW
Vaiden, 1991

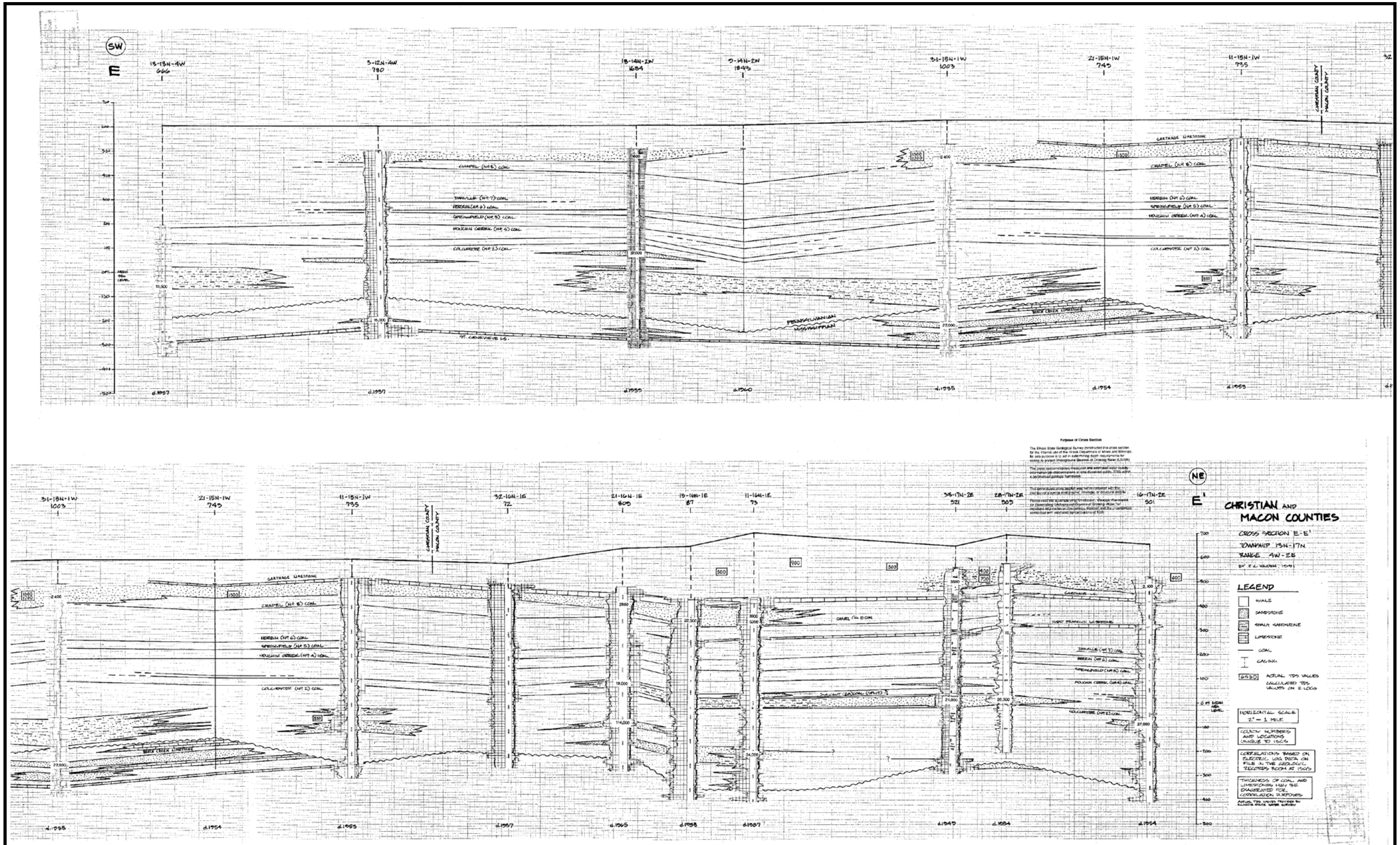
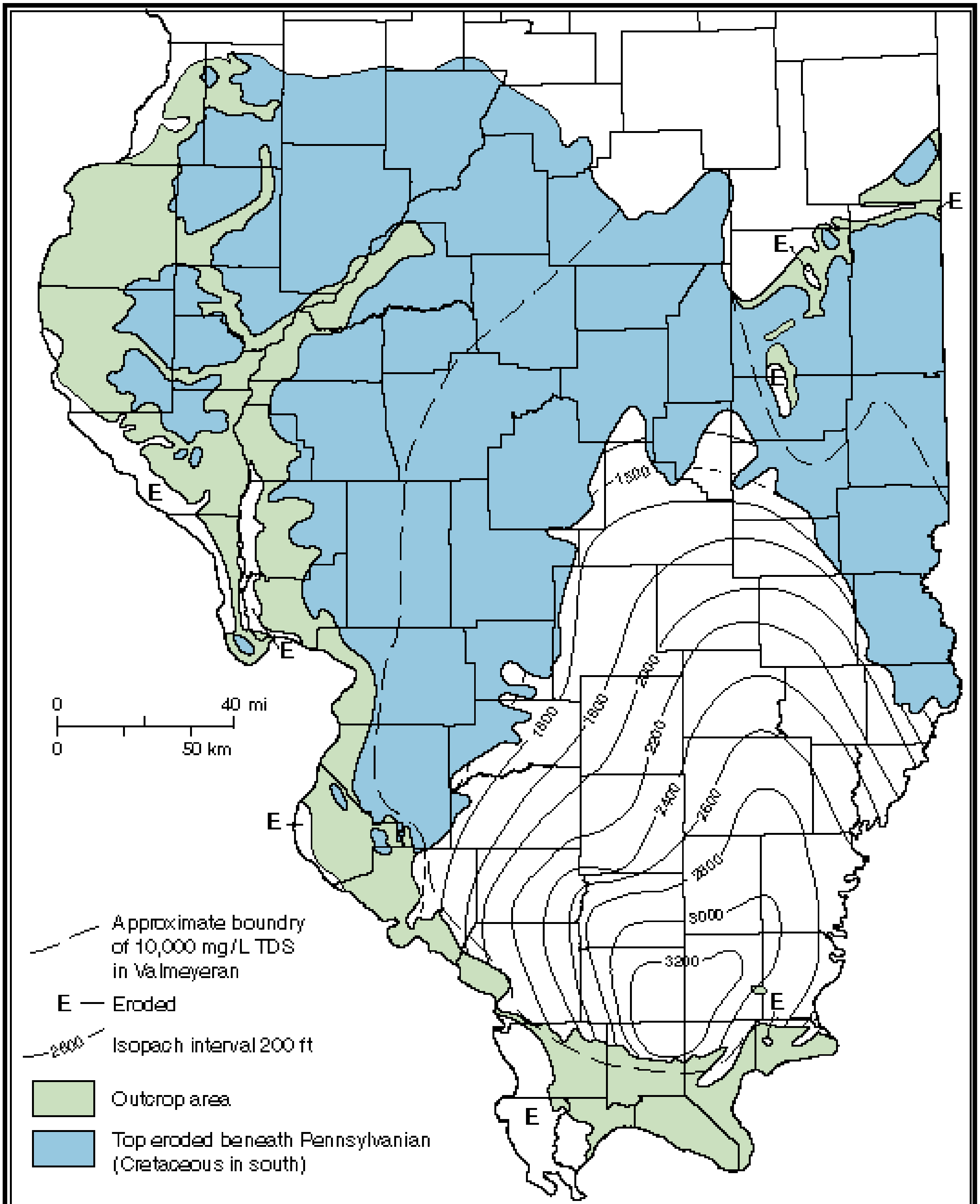


Figure 2 - 33 Pennsylvanian bedrock cross-section E-E' showing the depth to USDW
Vaiden, 1991



Thickness and distribution of the Mississippian System (William et al., 1975), and the boundary for 10,000 mg/L TDS in the Valmeyeran.

Figure 2 - 34 Thickness and distribution of the Mississippian System
(Willman et al., 1975), and the boundary for 10,000 mg/L TDS in the Valmeyeran.

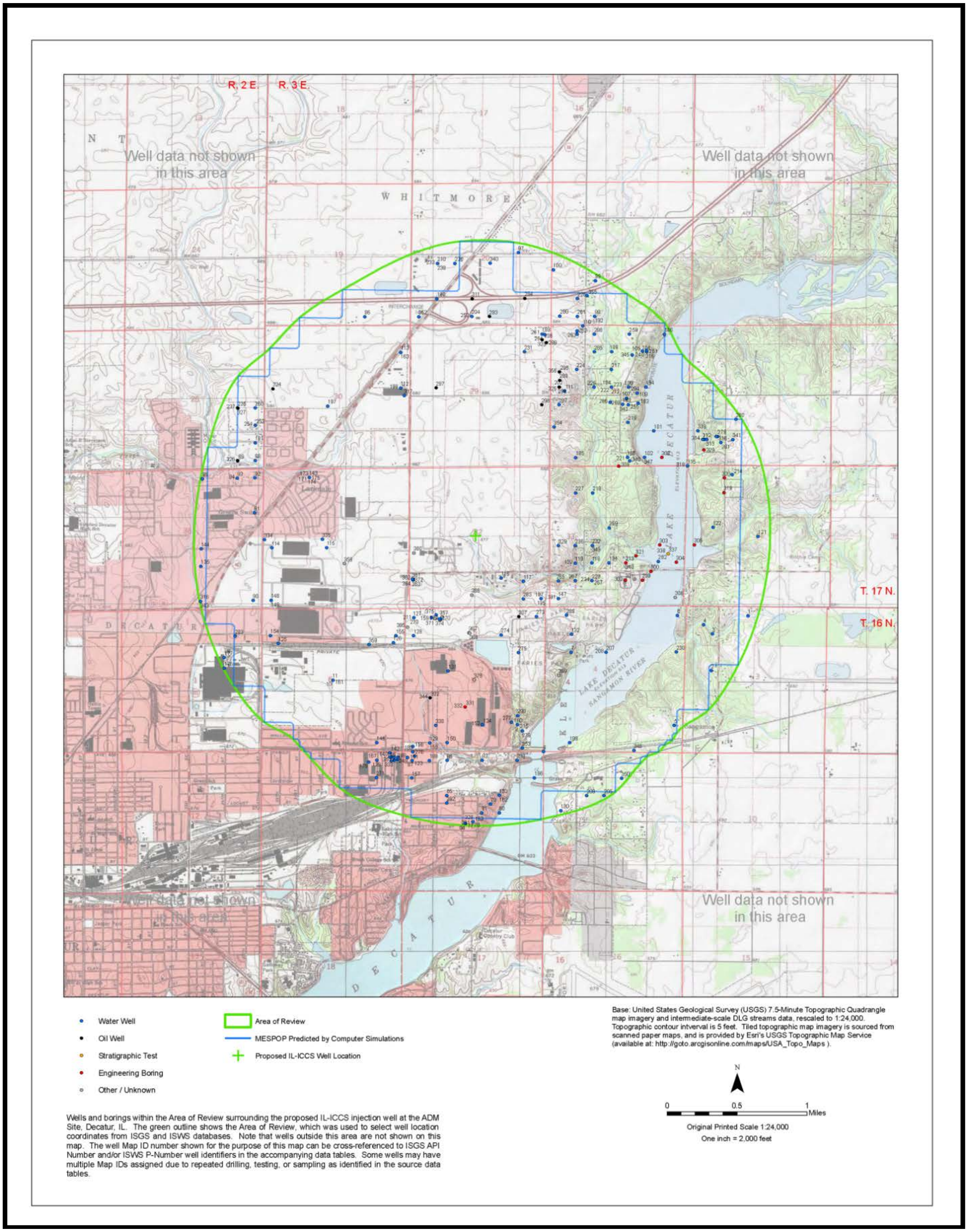


Figure 2 - 35 Wells, borings and other penetrations within approximate 2-mile radius of the site. Green cross shows the proposed injection well site. Well data were obtained from ISGS and ISWS well databases as of May 10, 2011.

3 WELL DESIGN AND CONSTRUCTION DATA

3.1 INJECTION WELL

3.1.1 Injection Well Location

The construction of the injection well, CCS #1, was completed in 2009. The closest municipality to the well is Decatur, Macon County, IL. The well is located on the surface 438 feet South and 1332 feet East in the Northwest quadrant of Section 5 of Township 16 North and Range 3 East at a surface elevation of 674 feet (205.4 meters) above Mean Sea Level (MSL). The latitude and longitude coordinates of the well in degrees-minutes-seconds are 39° 52' 36.9402" N and 88° 53' 35.721" W. The subsurface and surface design (casing, cement, and wellhead designs) exceeds minimum requirements to sustain the integrity of the caprock to ensure carbon dioxide (CO_2) remains in the Mt. Simon. Figure 3-1 shows a schematic of the injection well location and other well locations.

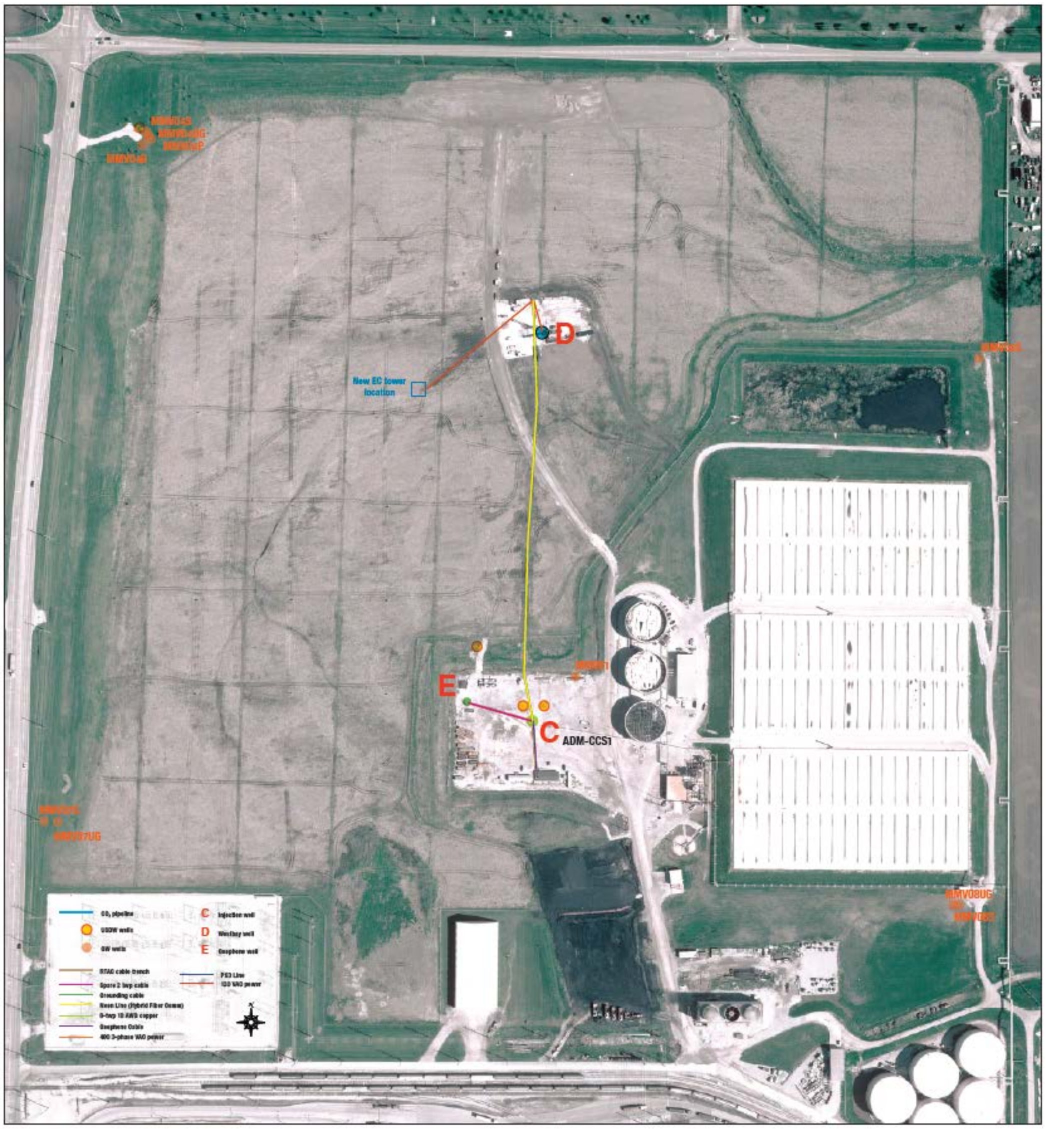


Figure 3 - 1 Injection, Verification, and Geophone well location.

3.1.2 Injection Well Casing, Cementing, and Completion

Figures 3-2 through 3-4 provide schematics showing subsurface and surface construction details of the well. The total depth (TD) of the well is 7236 ft (2205.5 m) and the static water level in the well is 430 ft (131 m) above MSL. Table 3-1 below summarizes the bit sizes used for drilling and the corresponding depth interval where the bits were used. The surface casing was set at 355ft, which well below the lowermost underground source of drinking water (USDW). The setting depth for the intermediate string is the top of the Eau Claire.

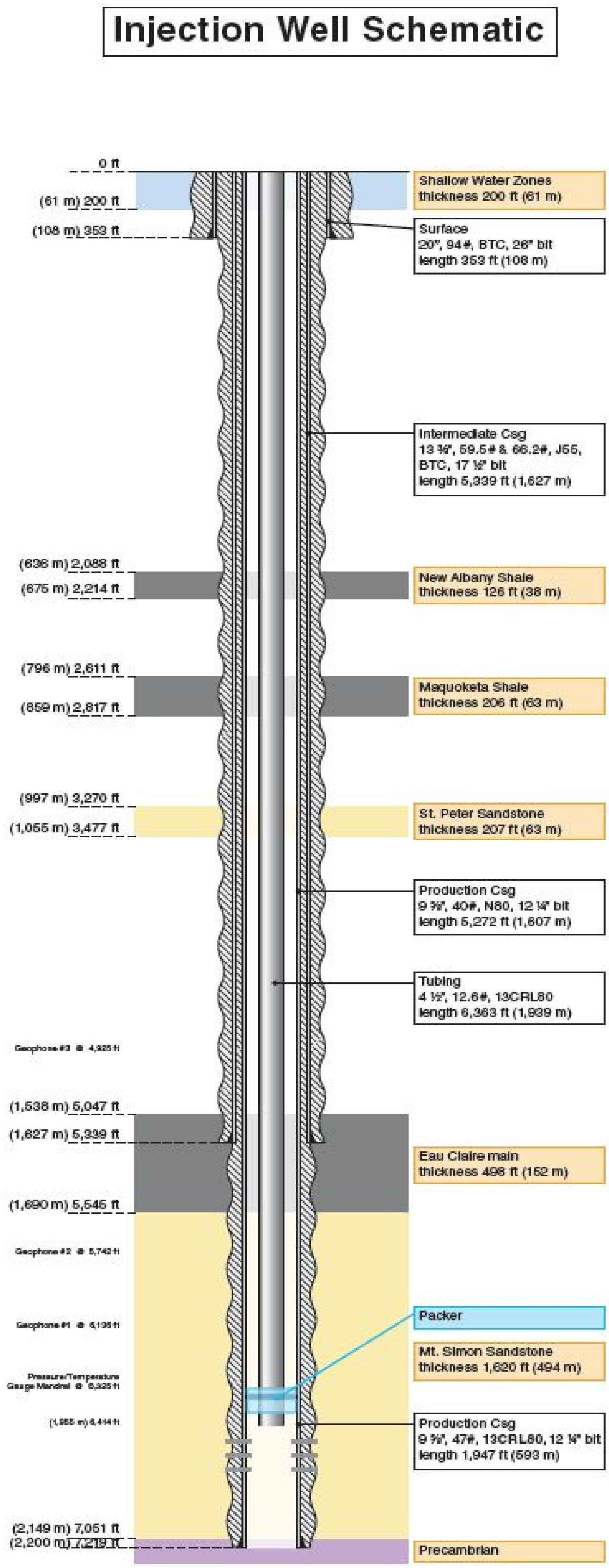


Figure 3 - 2 Injection Well Schematic

Schlumberger

Illinois Basin - Decatur Project

Prepared for : Paul Huges	Date : Nov-24-2009	Casing : 9 5/8" 40&47# N-80& CR13	Completion Type : Upper Compleation	Pressure/Temp. 3245psi BHP 135 Degree F
Field Name : Illinois Basin	Well Name : ADM CCS #1	Casing Drift ID 8.681/Drift 8.525	Rig: Wilson 28	
Prepared by : Roberto Schuldes	District/Phone # : Houma, LA / (985) 851-1074			
Production Tubing : 4 1/2" 12.6# CR13 JFE Bear				

String Weight Include Block -	Rig: Ideco H-35/Pioner Rig 15	
Block Weight -	Item's Actual Pipe Measured Length -	6335.32
Weight On Locator -	Packer Fluid Type and Weight -	9.4 ppg NaCl
Original RKB -	Completion Fluid Type and Weight -	9.4 ppg NaCl

All Depths Are Wireline Depths

				Production String Assembly
0.00	0.55	11.000	3.958	Hanger PN: HTG6561, Top Thread: 4-1/2 EUE 8rd
0.55	30.75	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joints (5.52+10.34+8.34+6.55)
31.30	4883.83	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing (Adjusted by 49.07)
4915.13	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
4925.47	9.97	8.350	3.958	Geophone #3
4935.44	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
4945.78	786.51	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
5732.29	10.36	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
5742.65	9.97	8.350	3.958	Geophone #2
5752.62	10.38	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
5763.00	236.64	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
5999.64	8.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6007.98	118.40	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
6126.38	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6136.72	9.97	8.350	3.958	Geophone #1
6146.69	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6157.03	157.96	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
6314.99	10.36	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6325.35	6.01	5.712	3.879	4 1/2, 12.60, SGM-FS, NDPG/NLOG, SINGLE, TUBING
6331.36	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6341.69	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6352.02	1.36	4.500	3.813	4 1/2" x 3.813 X-nipple JFE Bear
6353.38	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6363.71	2.08	7.000	3.500	4.75" Snap latch 13Cr (4 1/2 12.6# JFE Bear)
6365.79	9.00	4.690	3.500	4.75" Seal Unit 4.124" 13Cr SLHT pin x box ID:127088 PN:4
6374.79	0.81	4.690	3.500	X-O, 4.063-8 SA Pin x 4.124" 13Cr SLHT Box PN: 100714412
6375.60	2.51	4.724	3.750	SAGS w/ inner sleeve 13chr 4.063 8SA Box ID: 164949-01, PN:100602582/AA
6378.11				End of Assembly

Depth	Length	ID	OD	Quantum Max Packer Assembly
6363.71	6.47	4.750	8.341	9 5/8" x 4.75" (47-53.5#) Q-Max 13Cr w/HNBR ID# 250148-03
6370.18	0.83	5.443	7.013	X-O, 6.375" 6-SA Box x 6.25" 8-SA Box HOS-252940
6371.01	19.06	4.750	6.974	9 5/8" x 4.75" x 20' PBR PO# 101046
6390.07	1.14	3.431	6.950	X-O, 4" 11.6# NU 8rd Pin x 6.375" 6-SA Box HOS-252941
6391.21	10.33	3.442	4.752	4" NU 8rd 11.6# 13Cr85 Pup Joint w/ Collar
6401.54	1.54	3.313	4.744	4" x 3.313" X-Nipple C-36025-01
6403.08	10.31	3.442	4.745	4" NU 8rd 11.6# 13Cr85 Pup Joint w/ Collar
6413.39	0.71	3.672	4.780	4" NU 8rd 11.6# 13Cr85 Wireline Re-Entry Guide w/ mule shoe SO# 729775
6414.10				EOA

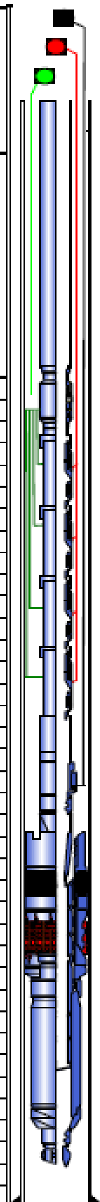


Figure 3 - 3 Packer and lower completion schematic for CCS#1

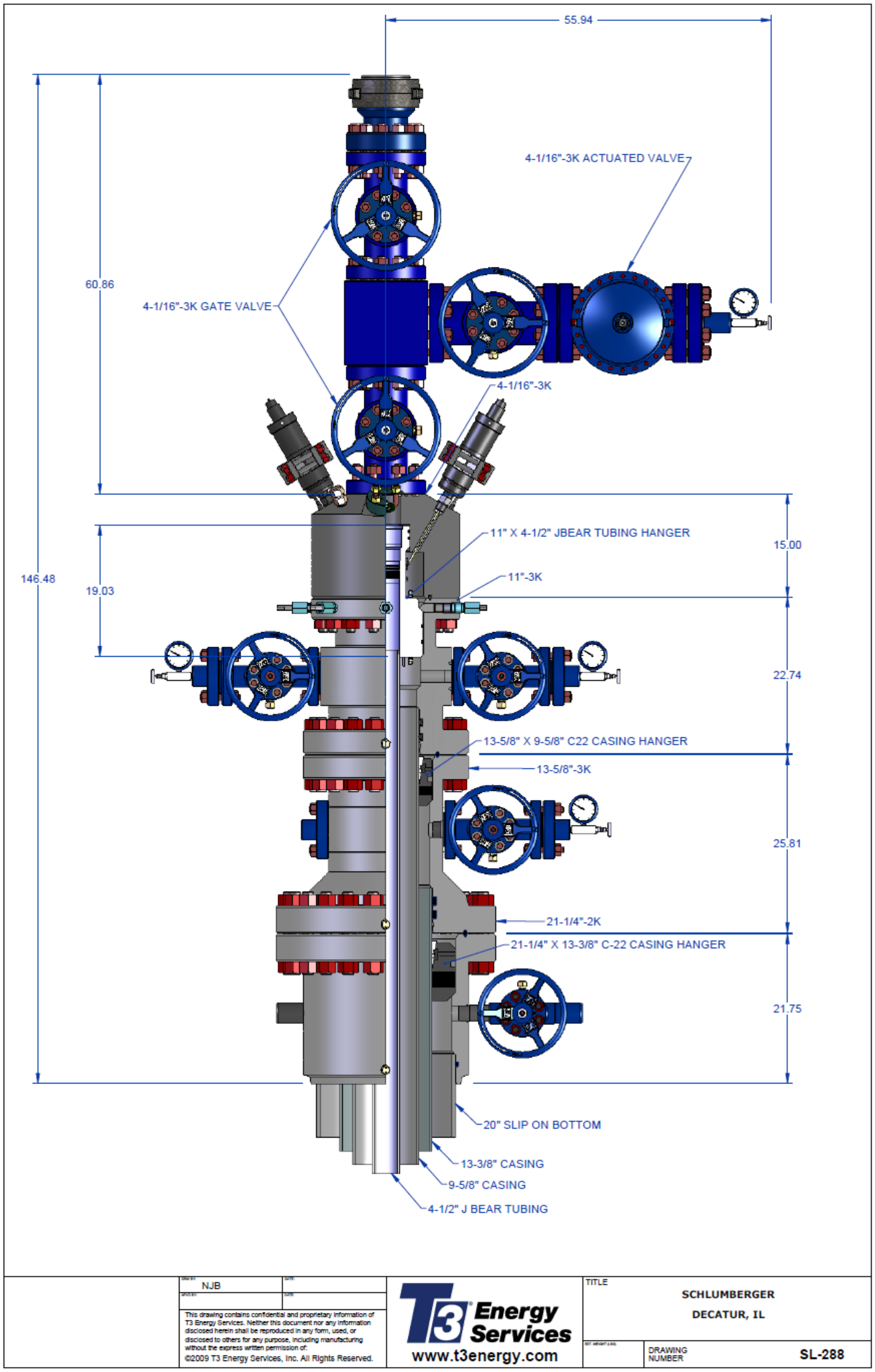


Figure 3 - 4 Schematic of the wellhead of the injection well.

Table 3 - 1 Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0-355	26	To bedrock
Intermediate	355-5,339	17 ½	To primary seal
Long	5,339-7,236	12 ¼	To TD

Each interval that was drilled was cased and cemented to surface. The casing for the surface and intermediate depths was mild steel, H40 (surface) and J55(Intermediate). The long string was cased with N80 steel to 5,272ft and L80 13Cr80 from 5,272 to 7,219. The injection tubing was run between 0 and 6,363. Based on joint strength the maximum allowable suspended weight of the tubing is 306,000 pounds and the actual weight of the tubing string in air is 79,539 lbs. The materials selected for the well could lead expected service life of at least 30 years. Table 3-2 provides additional detail on the casing and tubing used in the injection well.

Table 3 - 2 Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lbm/ft)	Grade (API)	Design Coupling	Coupling Outside Diameter (inches)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)
Surface	0-355	20	19.124	94	H40	8-round STC	21.00	29.02
Intermediate – Upper Section	0-3,630	13 3/8	12.515	59.5	J55	Long or Buttress	14.375	29.02
Intermediate – Lower Section	3630-5,339	13 3/8	12.415	66.17	J55	Long or Buttress	14.375	29.02
Long (carbon)	0- 5,272	9 5/8	8.835	38.97	N80	8-round LTC	10.625	31
Long (chrome)	5,272 - 7,219	9 5/8	8.681	47.0	L80 13Cr80	JFE BEAR	10.485	13
Tubing	0-6363	4 1/2	3.958	12.6	JFE 13Cr85	JFE BEAR	5.00	13

Injection Well Cement

The well is fully cased and perforated for injection into the lower Mt Simon formation. All strings of casing are cemented to surface. The lower portion of the long string was cemented using EverCRETE* CO_2-resistant cement system. The CO_2 resistant cement will be placed from total depth through the Eau Claire formation and back into the intermediate casing. A conventional blend lead slurry was pumped ahead of the CO_2 resistant cement to fill the annular space between the intermediate and long string casings. The intermediate and surface string were also cemented using conventional cement blends. Each of the cement formulations selected are appropriate for the expected fluids and in the well. The surface casing and long string casing were cemented in a single stage. The intermediate casing was cemented in two stages.

The lead cement system in the intermediate section was changed from that proposed in the Class 1 permit application submitted to IEPA due to lost circulation encountered while drilling the well. Lost circulation was encountered in the Knox at a depth of approximately 4,562 feet and again in the Ironton-Galesville at 5,017 feet. Both zones were sealed off with cement plugs, however, there was concern that during cementing operations the plugs might fail and lost circulation would be encountered while cementing. Therefore, the cement job was completed in two stages with a stage collar run at 3715 feet. The first stage cement was changed from a Class A system to Class H cement due to better performance characteristics of Class H cement – primarily lack of a gelation tendency present in Class A. The second stage lead system was changed from a 50/50 Class A- Pozzolan with 6% bentonite and 10% salt mixed at a density of 13.3 ppg to a 65/35 Class A Pozzolan system with 4% bentonite and 10% salt with 5 lbs/sk Kolite mixed at a density of 12.7 ppg in order to lighten the slurry, thus enabling cement to be circulated to surface. The difference in 24 hour compressive strength was small: 575 psi in 24 hours for the 65/35 system compared to 655 psi in 24 hours for the original 50/50 system. The actual job went very well with cement circulated to surface and good bonding.

For the long-string CO_2-resistant cement, EverCRETE, was used in the entire open hole section from TD and was placed approximately 500 feet back into the intermediate casing. The manufacturers specifications for EverCRETE are provided in Table 3-4. The final cementing program used is described in Table 3-3.

Table 3 - 3 Manufacturers Cement Specifications

BHCT (Bottomhole circulating temperature)	40 °C [104 °F]
BHST (Bottomhole static temperature)	50 °C [122 °F]
Specific gravity [lbm/gal]	15.9 ppg
Rheological properties determined with API R1B5 after mixing*	
PV (cp) (Plastic Viscosity)	454.623
T_y (lbf/100ft^2) (Yield Point)	28.45
After conditioning at BHCT	
PV (cp)	247.198
T_y (lbf/100ft^2)	28.16
10 second gel strength (lbf/100ft^2)	22
10 minute gel strength (lbf/100ft^2)	25
Then 1 minute stirring gel strength (lbf/100ft^2)	19
Stability	OK no sedimentation
API fluid loss at BHCT	0
Thickening time at BHCT	
30 Bc	1hr, 46 min
70 Bc (unpumpable)	4 hr, 18 min
UCA cell compressive strengths*	
50 psi	18 hr, 29 min
500 psi	21 hr, 07min
24 hour comp. strength psi	1177

Table 3 - 4 Cement Specifications for CCS #1

Casing	Depth Interval (feet)	Type/ Grade	Additives	Quantity (cubic yards)	Circulated to Surface	Thermal Conductivity (BTU/ft.hr. °F)
Surface (Lead)	0-350	Class A	0.2% D-46 Antifoam, 0.25 lb/sk Flakes	58	Yes	0.7
Surface (Tail)		Class A	1% CaCl, 0.2% D-46 Antifoam, 0.25 lb/sk Flakes	38.67	No	0.7
Intermediate-Sage 1 (Lead)	3,715-5,339	Class H	D081 Retarder 0.040 gal/sk, D047 Antifoam 0.020 gal/sk	54.7	Yes	0.71
Intermediate-Sage 1 (Slurry)		Class H	D081 Retarder 0.080 gal/sk, D047 Antifoam 0.020 gal/sk	46.3	No	0.75
Intermediate-Sage 1 (Tail)		Class H	D081 Retarder 0.080 gal/sk,	45.8	No	0.78

Casing	Depth Interval (feet)	Type/ Grade	Additives	Quantity (cubic yards)	Circulated to Surface	Thermal Conductivity (BTU/ft.hr. °F)
			D047 Antifoam 0.020 gal/sk			
Intermediate-Sage 2 (Lead)	0-3,715	35/65 Class A-Pozzolan	D020 Extender 4.000%BWOB D044 Salt 10.000% BWOW, D065 Dispersant 0.600%BWOB D167 Fluid Loss 0.200%BWOB, D046 Antifoam 0.200%BWOB, D042 LCM/extender 4.787 lb/sk blend	221.3	Yes	0.47
Intermediate-Sage 2 (Slurry)		35/65 Class A-Pozzolan	D020 Extender 4.000%BWOB D044 Salt 10.000% BWOW, D065 Dispersant 0.600%BWOB D167 Fluid Loss 0.200%BWOB, D046 Antifoam 0.200%BWOB, D042 LCM/extender 4.787 lb/sk blend	239.2	No	0.5
Intermediate-Sage 2 (Tail)		Class H	D081 Retarder 0.020 gal/sk, D047 Antifoam 0.020 gal/sk	38.67	No	0.72
Long (Lead)	0-4,170	35/65 Class A-Pozzolan	D020 Extender 6.000%BWOB D167 Fluid Loss 0.400%BWOB,	249.5	Yes	0.47

Casing	Depth Interval (feet)	Type/ Grade	Additives	Quantity (cubic yards)	Circulated to Surface	Thermal Conductivity (BTU/ft.hr. °F)
			D046 Antifoam 0.200%BWOB			
Long (Tail)	4,170-7219	EverCRETE CO2 Resistant Cement	D081 Retarder 0.035 gal/sk blend D168 Fluid Loss 0.170 gal/sk blend D206 Antifoam 0.030 gal/sk blend D080 Dispersant 0.050 gal/sk blend	112.1	No	0.72

Packer

The packer (Figure 3-3) used in the completion assembly is a seal bore, retrievable production packer. Specifically, the packer was a Schlumberger QUANTUM MAX* system for HPHT conditions Type III Service Tool, Q-Max 13 Chrome designed for 9.625-inch outer diameter casing with linear weights ranging from 47 – 53 lb/ft. It was located within the Mt Simon formation inside the long-string casing. The top of the packer was set at a wireline-referenced depth of 6363.7 feet (1939.6 meters) with the center of the sealing elements at 6365 feet (1940 meters).

Perforation Depths

A relatively high permeability zone in the lower Mt. Simon is the planned injection interval. The approximate gross interval is 6,700 feet to 7,050 feet. The well was perforated between 6982 and 7012 ft and 7025 and 7050 ft. The perforations were shot using 6 shots per foot and a shot phasing of 60 degrees Further detail on perforation and stimulation is found in Section 3.1.6.

Wellhead

The design for the injection well includes a single master and single wing Christmas tree assembly with a swab valve above flow tee. Wing valve with a check valve installed directly upstream of the valve to prevent backflow into the pipeline. Figure 3-3 shows details of the wellhead. Note that the wing valve and check valve positions were reversed during construction to insure that CO_2 would not be trapped between the two valves. See Appendix B - Surface Facilities Instrumentation Summary for gauge details.

Pressurized Annulus and Annular Fluid

The wellbore was filled with approximately 500 barrels of 9.4lb/gal sodium-chloride brine with corrosion inhibitor and oxygen scavenger additives before installing the lower portion of the injection the packer. This fluid remained in the well as the upper completion including the tubing, seal-bore assembly, and sensors were deployed and latched into the polished bore receptacle of the packer body. This is also the fluid now comprises the annular fluid between the long-string and the tubing. The annular fluid has a specific gravity of 1.127 and a hydrostatic gradient of 0.488 psi/ft.

Annulus Protection System

Section 146.88(c) of the "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells" requires that the annular space between the long-string casing and the tubing be at a higher pressure than the pressure within the injection tubing. However, this section also provides room for director discretion on the necessity of this requirement if the pressure will harm the integrity of the well and under the existing IEPA Class 1 Non-Hazardous Injection Permit the annular protection system has been constructed to a different but equally protective standard.

The annulus protection system is designed to preclude any unpermitted fluid movement into or out of the annulus. The annulus between the tubing and the long string of casing is filled with 9.4 lb/gal NaCl brine (described above). The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) at all times which will ensure the pressure within the annular space can easily be monitored. Additionally, surface pressure coupled with the heavy brine in the annular space povides a positive net pressure immediately above the packer.

Research and observation in the field of well integrity has shown that over-pressurizing a cemented casing can lead to debonding of cement and the creation of a microannulus. The micro annulus can in-turn act as a leakage pathway for gas allowing for fluids or gasses to move between formations. The Minerals Management Service [Sabins, 2004] and Bourgoyne et al. [1999] have pointed to high internal pressure as the cause for loss of integrity of a primary cement job. Goodwin and Crook, [1992] note that long-term influx (of fluid or gas) generally occurs after excessive casing test pressures after the cement is set. In field observations Goodwin and Crook noted that the loss of integrity normally takes place in the lower third to half of the well. In their lab work, Goodwin and Crook note minor cement sheath damage at an internal pressure of 2,000 psi, major damage at 4,000 psi, and catastrophic damage at 6,000 psi. Other authors have also conducted work on the creation of annuli or leakage pathways due to excessive pressurization of cemented casing. Lab work by Teodoriu et al. [2010] also showed that that pressure internal pressure can create or cause cement debonding and leakage. In Teodoriu et al., a 400 bar (5801 psi) caused the cement in their test sample to debond from casing.

This research presents a strong case for having the pressure in the annular space lower than the pressure in the injection tubing. Safe and effective well operation will still be achieved by monitoring the pressure in the annulus for sudden changes and responding to those changes quickly and appropriately. Under the Class VI Scenario, if we assume that we are 100 psi over the injection pressure at the top of the well the pressure change will be 1189 psi. While it is possible that either scenario could cause some damage to the bond between the cement and casing or to the cement sheath we feel that the proposed scenario where the maximum change is under 2000 psi (where Goodwin and Crook noted minor damage) will be unlikely to damage the integrity of the well. Figure 3-5 shows estimates of the annular pressure in the well based on the scenarios presented here.

In addition, under the Class VI annular scenario the annular pressure in the tubing at the depth range of the Mt Simon will be above formation fracture pressure.   If a leak occurs in the casing at this depth the formation could be damaged and annular fluid could be lost the to formation and the cement bond responsible for zonal isolation could be damaged.

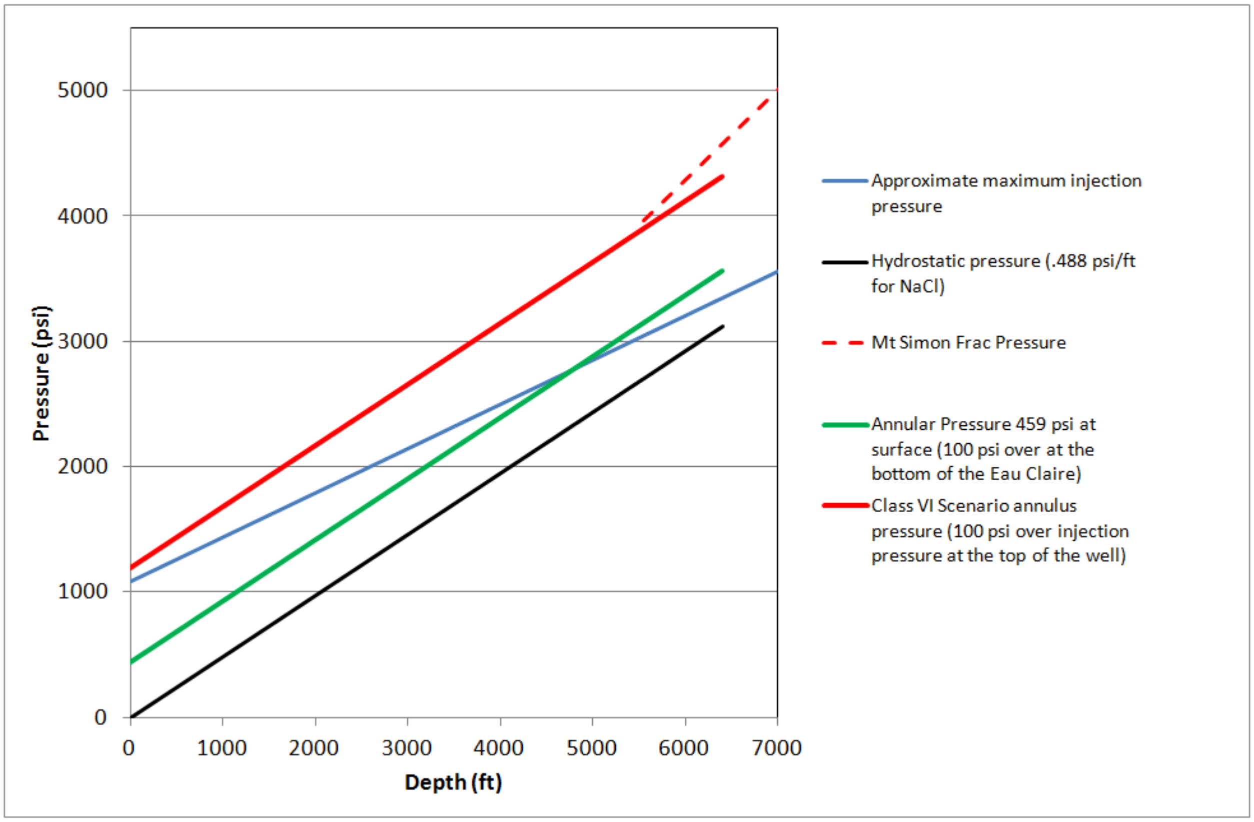


Figure 3 - 5 Annular pressure scenarios.

Note: the scenario in red represents the annular pressure under the UIC Class VI without director discretion and the green scenario represents the proposed annular protection system.

Figure 3-6 shows the injection well annulus protection system. The annular monitoring system consists of a continuous annular pressure gauge, a NaCl water storage reservoir, a low-volume/ high-pressure pump, a control box, fluid volume measurement device and fluid and electrical connections. The control box is programmed to operate the pump as needed to keep the annulus pressurized to 400 psi (or greater). A means to monitor the volume of fluid pumped into the annulus is incorporated into the system by use of a tank fluid level gauge.

The annulus pump is a General Pump Co. Model 1321 triplex pump rated to 2,100 psi with a flow rate of 5.5 GPM. The pump is powered by a 3.0 HP Marathon 110/220v electric motor. The pump is controlled by two Barksdale Series 7000 pressure switches; one switch for low pressure to engage the pump and the other switch for high pressure to shut the pump down. The Barksdale pressure switch is manually adjustable to maintan pressure as required by the permit. Annulus pressure will be monitored at the ADM data control system. A 250 gallon, NaCl brine storage tank will be connected to the suction inlet of the pump. A hydrostatic tank level gauge will be installed in the brine storage tank. The NaCl brine in the storage tank will be the same brine as in the annulus. The annular pressure will be monitored by the ADM control system using an ABB 264HSVKTA1L1N2 or similar pressure gauge. Average annular pressure and fluid volumes changes will be recorded daily.

If there is a loss of electrical power to the annulus re-pressure system, annular pressure will be continued to be monitored by the pressure transducer or the pressure gauge. If the annulus pressure is stable and within the operating range, no action will be taken for power failures of 12 hours or less. If the power failure is expected to go beyond 12 hours or if the annulus pressure is falling below operating range, then a portable generator will be connected to the annulus pressure system. In an event where it is apparent that a positive pressure of at least 400 psig cannot be maintained, or that pressure above the packer cannot be maintained higher than the injection pressure into the injection zone, then injection will be shut down until repairs can be made.

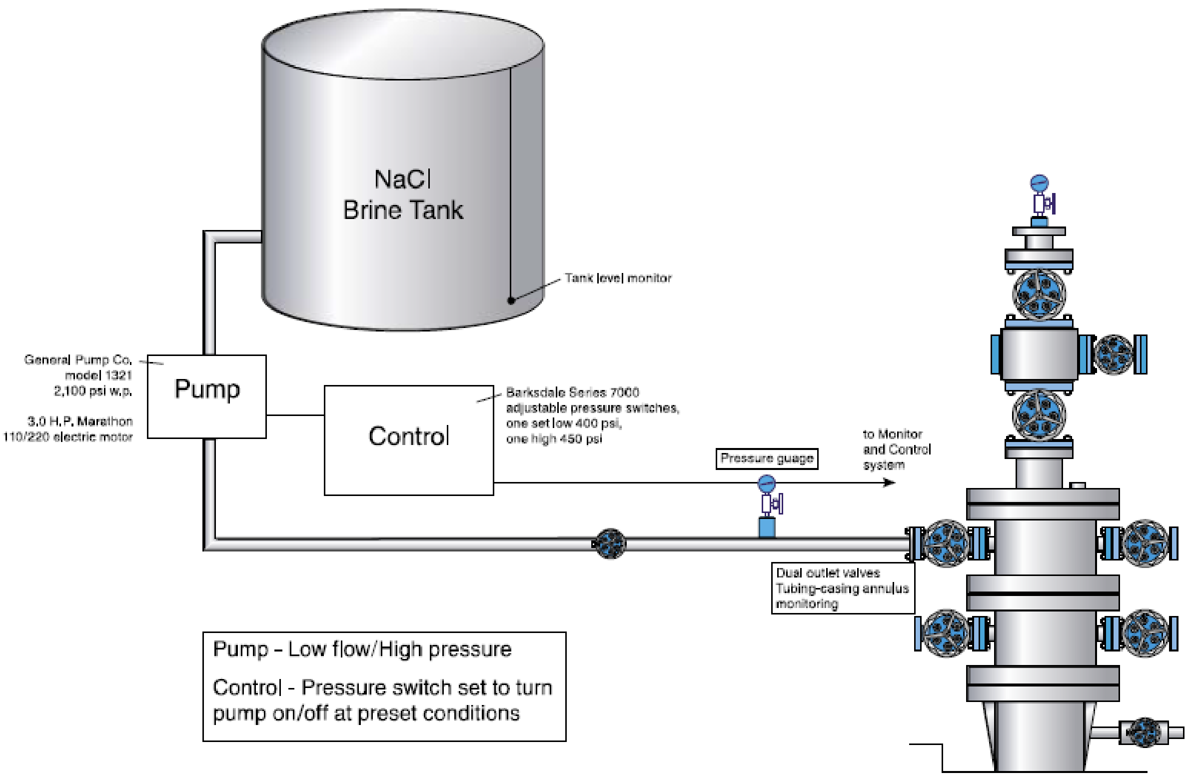


Figure 3 - 6 Annular protection system general layout

Drilling Contractor

The well was drilled with a rotary-table drilling rig with a waterbased circulating mud system. Contact information for the drilling company is listed below.

Les Wilson Inc.
215 Industrial Ave.
Carmi, IL 62821
(618) 382-4666

Contact Person: Bob Wilson

3.1.3 Injection Fluid Compatibility

The injection and confining zones are expected to react little with the injection stream. CO_2 is expected to have negligible to no reaction with the formation minerals and formation fluid. Any reactions that may occur are not expected to affect the containment of the CO_2 below the primary seal. Components to the injection wellhead and wellbore have been selected to minimize and negate any reaction with the CO_2.

Compatibility with Minerals in the Injection Zone and Formation Fluid

Geochemical modeling using Geochemist's Workbench (Bethke, 2006) was conducted to examine the possible effects of injecting supercritical CO_2 into the site (Berger et al., 2009). The model was based on chemical and mineralogical data from the Manlove Gas Storage Field in Illinois. The simulation predicted that as the CO_2 reacts with the Eau Claire formation, illite and smectite will initially dissolve and the dissolved CO_2 could be precipitated as carbonates. This dissolution and precipitation process is not expected to affect the caprock integrity.

In the Mt Simon formation, Berger et al. predicted that illite and glauconite dissolve initially and as the reaction proceed, kaolinite and smectite precipitated. The injected CO2 initially lowers the formation pH to about pH 4.5 but as the reaction with the formation progressed the pH was predicted to increase to 5.4. The model also predicts that the volume of pore space will not be significantly altered (Berger et al., 2009). Therefore, no compatibility problems, such as a major reduction in injection permeability resulting from chemical precipitates, are expected.

Compatibility with Injection Well Components

All of the components of the well that will come into contact with the injection stream have been designed to be compatible with CO_2. The CO_2 will be transferred from the surface compression facilities to the wellhead via approximately 6400 feet of 6-inch Schedule 40 carbon steel pipeline. The surface facility gas dehydration unit will reduce the water content of the CO_2 to a range of 7 to 30 lb of H_2O/MMSCF (150 to 630 ppmv H_2O). This water content range is consistent with typical U.S. CO_2 transmission pipeline water content specifications for carbon steel pipe, therefore, no corrosive reactions are anticipated. Although the CO_2 will be dry, the injection tubing is composed of chrome steel (13 Cr) and is specifically engineered to function in environments with high concentrations of wet CO_2 so it will also be fully compatible with the injection stream.

The annular fluid between the injection tubing and the long string casing is a 9.4 lb/gal sodium chloride brine with corrosion inhibitor and oxygen scavenger additives that will minimize corrosion to the tubing and casing. Reactivity between the injected CO_2 and the annular fluid is expected to be negligible because the CO_2 and annular fluid are not expect to come in contact with each other. However, the CO_2 and annular fluid are compatible should they come in contact.

The packer is a Schlumberger QUANTUM MAX Type III Seal-bore Assembly packer composed of chrome steel (13 Cr). The sealing elements of the packer and seal-bore assembly are comprised of Nitrile rubber which is designed to be durable in environments with high CO_2 concentrations. As a result, reactivity between the CO_2 and the injection packer is expected to be negligible.

Components of the wellhead equipment expected to be in contact with the injected CO_2 are constructed from schedule 310 and 410 stainless steel; therefore, no adverse reactions are expected between the injected CO_2 and any the wellhead components.

The long string casing from 5,272 in the confining unit to TD is composed of chrome steel (13 CR) and, like the tubing, is specifically engineered to function in environments with high concentrations of CO_2. The long string casing from 5,272 to surface is carbon steel. This section of casing, however, is above the cap rock and will remain isolated from the injected CO_2 by the tubing inside and the cement sheath on the outside. The cement sheath is also engineered for the exposure to separate phase and dissolved CO_2. EverCRETE, (described above) was placed from 4,10 to TD. The EverCRETE portion of the sheath extends from TD into the intermediate casing and will act as a barrier for CO_2 to travel up the backside of the casing and reach the non-CO_2 resistant cements. The rest of the long string and other casing strings are cemented with conventional well cements and are compatible with the brines they may be exposed to.

3.1.4 Monitoring Hardware

Details of the various process monitoring sensors and gauges are summarized below and include the location of the device, the brand and model number, the device type (electrical or mechanical), and whether or not the device is continuously recording. All of the hardware is selected so that the operating range exceeded the expected maximum operating range of the injection well by more than 20 %.

Table 3 - 5 Monitoring hardware specifications.

Hardware	Make	Model	Type	Operation	Operating Range	Location
Surface Injection Pressure Gauge	ABB	264HSVKTA1L1N2	Electrical	Continuous Recording	0-2,440 psig	Installed directly into the wellhead tree cap port (PIT-009*)
Downhole Injection Pressure Gauge	Schlumberger	NDPG-CA (P/N 500897)	Electrical	Continuous Recording	0-10,000 psig	Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.
Casing-Tubing Annular Pressure Gauge	ABB		Electrical	Continuous Recording	-14.7-1000 psig	Mounted on the wellhead port open to the casing-tubing annulus.
Flow meter	SCADASense	4203	Electrical	Continuous Recording	250-1,100 tonnes/day	Installed downstream of the multistage centrifugal pump (FIT-006+)
Surface Temperature Gauge	INOR	Meso-HX 70MEHX1001	Electrical	Continuous Recording	-60 – 140 °f	Installed downstream of the multistage centrifugal pump along the section of pipeline immediately upstream of the wellhead wing valve inlet and check valve. (TIT-009)
Downhole Temperature Gauge	Schlumberger	NDPG-CA (P/N 500897)	Electrical	Continuous Recording	0 – 212 °f	Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.

+Denotes the identifier on the Process Controll Stratedgy Diagram Located in Appendix C

3.1.5 Tests and Logs

During Drilling

Prior to setting casing each open hole section was logged with multiple tools to fully characterize the formations in the geologic column. Both the intermediate and final holes were logged, tested, and sidewall cored. In addition, whole core was collected from the final hole. The open-hole loging, coring, and testing suites for the intermediate and final holes are described below and more detailed description is available in Appendix A, titled CCS#1 Well Completion Report Supplemental.

Intermediate Hole:

Wireline Logs,tests, and cores:
- Compensated Neutron Porosity
- Photoelectric Factor & Bulk Density
- Resistivity
- Micro-Resistivity Imaging (“fracture finder”)
- Sonic
- ECS* elemental capture spectroscopy sonde
- Natural Gamma Ray Spectroscopy
- Magnetic Resonance
- Rotary Sidewall Cores

Drill Stem Test

Final Hole:

Wireline Logs, tests, and cores:
- Compensated Neutron Porosity
- Photoelectric Factor & Bulk Density
- Resistivity
- Micro-Resistivity Imaging (“fracture finder”)
- Sonic
- ECS
- Natural Gamma Ray Spectroscopy
- Magnetic Resonance
- Rotary Sidewall Cores
- Formation Pressure Measurements & Fluid Samples
- ‘Mini’ Fracture Pressure Measurement
- Zero-offset Vertical Seismic Profile

Whole Cores: (Description of test procedures included in File Box)
- Core #1: 5474’ – 5504’

Core #2: 6404' – 6434'
Core #3: 6750' – 6780'

During and After Casing Installation

After casing and cementing the wells were logged to ensure the integrity of the cement job. Due to the large surface casing size, a cement bond log with radial imaging could not be run. however, a conventional cement bond log (CBL) was run. Cement evaluation logs in very large casings typically can be ambiguous and are qualitative at best.

A ultrasonic cement imaging logs with radial capability was run on the intermediate casing. A CBL with radial capability and an ultrasonic cement imaging log with radial capability was run on the long-string casing. Ultrasonic imaging logs provided casing thickness, internal radius, and cement evaluation data that were used to assess the integrity of the well and act a baseline for future comparison. In addition to the cement bond and ultrasonic logs a multi-finger caliper (PMIT) and other wellbore integrity logs were also run. The PMIT is used to baseline the condition of the inside of the casing and as verification for the measurements using the ultrasonic cement log. All logs showed satisfactory conditions for preventing fluid migration.

A baseline thermal neutron decay logs using the RST* Reservoir Saturation Tool and temperature log were run as a baseline for comparison with future passes during and after injection. Differences and similarities between the different passes will show if the CO_2 has moved vertically. A list of each of the logs an tests run in each casing is below:

Surface Hole: (Logs included in File Box)
- Wireline Logs:
  - Variable Density Cement Bond Log

Intermediate Hole: (Logs included in File Box)
- Wireline Logs:
  - Ultrasonic Cement Imaging

Final Hole:
- Wireline Logs: (Logs included in File Box)
  - Ultrasonic Cement Imaging
  - Variable Density Cement Bond Log
  - Pressure/Temperature Log
  - Thermal Neutron Decay (Formation Sigma) Log
  - Multi-finger Casing Caliper Log
  - Casing Collar and Perforating Record Logs
  - Injection Full Bore Spinner Logs
- Injectivity Testing: (Results included in File Box)
  - Step-rate Test

Pressure Fall-off Tests

The CBL on the surface string of casing shows that at 352 ft. the amplitude measures just under 2 mv. This translates into an attenuation of 9 dB/ft. Using this value to compute the compressive strength of the cement at this interval, a value of approximately 3000 psi is computed. To demonstrate zone isolation it is desirable to have a continuous interval with the attenuation greater than 6 dB/ft. The attenuation is greater than 6 dB/ft from 354 to 347.5 ft. Ideally an interval longer than this would be preferred to indicate hydraulic isolation. However, there are several additional considerations. The CBL tool is designed for use in smaller casing, yet there are no better tools to evaluate the cement in this large casing. In addition to the zone mentioned above, several other intervals in the well have attenuations in the 4 to 6 dB/ft range where cement is certainly present. Also, it is known that cement was circulated to surface and that the cementing job was executed according to plan. Given this information it is believed the CBL is showing good hydraulic isolation at the base of the casing and a sufficient amount of cement behind the entire interval to prevent any fluids from flowing up from below into any USDW behind the casing in this interval as is the objective of this casing string.

The USIT shows that the intermediate string of casing has good hydraulic isolation over most of the length of the casing, with only short intervals where there are isolated pockets of fluid and not cement behind the casing The USIT log also shows that the casing has no internal or external defects at this time based on the internal radius and thickness measurements.

The production string of casing was also determined to have good hydraulic isolation over most of the length of the casing, with only short intervals where there are isolated pockets of fluid and not cement behind the casing. The top of the injection zone is 5544 ft. and the first of these intervals below this point that has any potential to flow fluids is from 5660 to 5664 ft. It is actually more likely that this zone has a thin cement sheath rather than a channel. The next interval below this that is not completely isolated is from 6760 to 6750 ft. Above the base of the confining layer the first potential channel would be just above 4900 ft. Therefore, there is no potential for any fluids to migrate from the injection zone to zones above the confining layer by way of the casing-formation annulus.

It was also determined that a microannulus does exist in a few places between the casing and cement. This is a condition where the acoustic coupling between the casing and cement has been reduced. The CBL log is the tool most affected by this condition and a CBL log with 500 psi pressure applied to the wellbore fluids was enough to eliminate this condition. Based on the API data on casing expansion this would mean that the microannulus is less than one thousandth of an inch, which is prohibitive to fluid flow. The USIT measurement is the better measurement to use for the analysis in these intervals and it shows very good hydraulic isolation. The USIT part of the Isolation Scanner and the PMIT also show that the casing has no internal or external defects at this time based on the internal radius and thickness measurements. Appendix E (ADM CCS#1 Mechanical Integrity Log and Testing Descriptive Report) further details the logging that was conducted on the cased-well

3.1.6 Demonstrate Mechanical Integrity Prior to Operation

Mechanical integrity was established several times during the well completion. Prior to perforating the casing was tested by both a low and high pressure test. Upon installation of the lower completion the packer elements were successfully tested to 1000 psi. After the completion brine was spotted and the blanking plug was set in the lower completion the casing and lower completion was tested overnight to 750 psi. After installation of the upper completion and packer seal assembly the annulus was tested to 1000 psi however this test was not recorded. Details of all these tests can be found in the daily completion reports. On April 27, 2010 annulus was re-pressured to 1000 psi and was tested for one hour. Test was witnessed by McNDT. Details of equipment and test results are in the attached documents. Test was successful with pressure fall off of 5 psig in one hour. Tubing pressure was monitored via downhole sensor with no change in downhole tubing pressure. Appenix A – CCS # 1 Completion Report and Appendix E - ADM CCS#1 Mechanical Integrity Log and Testing Descriptive Report provide additional details on the MIT tests.

Description of Well Stimulation

The injection interval was subjected to a small-scale acid injection delivered in two distinct pumping stages following the addition of perforations. Each acid injection was designed with the primary intention of reducing near-wellbore drilling or ‘skin’ damage. The chronology of these injections is as follows:

25-Sep-2009: The interval perforated from 7025’ to 7050’ was acidized with 1,500 gallons of 15% HCl acid and displaced into the formation with 123 barrels of freshwater with a potassium chloride substitute additive.

30-Sep-2009: The intervals perforated from 6,982’ to 7,012’ and 7025’ to 7050’ were acidized with 3,000 gallons of 15% HCl acid. The acid was pumped in four 750-gallon stages with 500 gallon spacers of freshwater with a potassium chloride substitute additive between each acid stage. The acid was then displaced into the formation with 121.5 barrels of freshwater with a potassium chloride substitute additive.

3.1.7 Abandonment After Injection

<u>Removal of subsurface well features:</u> Casing: All casing used in this well will be cemented to surface and will not be retrievable at abandonment after injection.

<u>Tubing and Packer:</u> After injection, the injection tubing and packer will be the only injection equipment in the cased hole. Every attempt will be made to remove the injection tubing and

packer. If the packer cannot be released and removed from the cased hole, an electric line with tubing cutter will be used to cutoff the tubing above the single packer.

Plug Placement Method: The Balanced Plug placement method will be used. This is a basic plug spotting process that is generally considered more efficient and considered compliant with accepted industry practices.

Type and Quantity of Plugging Materials, Depth Intervals

In addition to the proper volumes, placement of plugs on depths approved by the agency (the minimum requirements), all cement will be previously tested in the lab, a CemCADE* cementing design and evaluation software will be run using actual well information such as actual depth, temperature on bottom, hole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug.

All casing will be cemented to surface and no casing will be retrieved. From the surface, at least 3 feet of all the casing strings will be cutoff well below the plow line and a blanking plate with the required permit information will be welded to the top of the cutoff casing.

Detailed Plugging and Abandonment Procedures

Notifications, Permits, and Inspections (Prior to Workover or Rig Movement)

Notifications, Permits, and Inspections are the same for plug and abandonment during construction and post-injection.

1. Notify Illinois EPA and/or US EPA (as appropriate) 48 hours prior to commencing operations. Insure proper notifications have been given to all regulatory agencies for rig move.
2. Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and ADM have written permission to proceed with planned ultimate P&A procedure.
3. Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.
4. Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.
5. Make sure partners (U.S. DOE, IEPA and/or US EPA, and ADM) approvals have been obtained, as applicable.

6. Make sure all necessary forms for Schlumberger paperwork are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.

Table 3 - 6 Plugging & Abandonment Contact List

Name	Department/Pos	Office	Fax	Mobile	Home
Paul Hughes, P.E.	Schlumberger Operations	281-340-8658	281-285-0165	832-715-9060	281-781-8545
Robert J. Finley	ISGS Project Management	217-244-8389	217-333-2830	217-649-1744	217-384-6841
Tom Stone	ADM Project Engineer	217-424-5897			
Mark Atkinson	ADM Environmental Coordinator	217-451-2720			

Volume Calculations

Volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1. Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2. Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

3. See generic calculations in the well plugging plan (Section 8) and have Schlumberger cementer and wellsite supervisor both review calculations prior to spotting any plug.

Note: For each cementing operation the Schlumberger cementer and the wellsite supervisor will verify via the cementing handbook or iHandbook all calculations and have the Project Manager approve the manner and procedure for said cementing operations. Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

Plugging and Abandonment Procedure for "After Injection" Scenario

1. Mobilize workover (WO) or Plugging Rig Equipment. Give appropriate notice before commencing operations.

2. Move in rig to ADM CCS#1 location. Notify the Project Coordinator before moving rig. Ensure all overhead restrictions (telephone, power lines, etc) have been adequately previewed and managed prior to move in and rig up (MI & RU). All CO_2 pipelines will be marked and noted to WO rig supervisor prior to moving in (MI) rig. Move rig onto location per operational procedures.

3. Conduct a safety meeting for the entire crew prior to operations, record date and time of all safety meetings and maintain records on location for review.

4. Make daily "Project Inspection" walks around the rig. Immediately correct deficiencies and report deficiencies during the regulatory discussion during morning meetings/calls. Maintain International Association of Drilling Contractors (IADC) or plugging reports daily at the WO rig log book or doghouse.

5. MI rig package and finish rigging up hoses, hydraulic lines, etc.

6. Open up all valves on the vertical run of the tree. Check pressures.

7. Rig up pump and line and test same to 2,500 psi. Fill casing with kill weight brine (9.5 ppg). Bleeding off occasionally may be necessary to remove all air from the system. Keep track and record volume of fluid to fill annulus (Hole should be full). If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.

8. If needed, if well is not dead nor pressure cannot be bled off of tubing, rig up (RU) slickline (SL) and set X-lock plug in X nipple located in X-Plug in tailpipe below packer. Circulate well with kill weight brine. Ensure well is dead. ND tree. NU BOP's and function test same. BOP's should have 4 ½"single pipe rams on top and blind rams in the bottom ram for 4 ½" Test BOP's as per local, state or federal provisions or utilize higher standard, 30 CFR250.616. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TIW's, IBOP's choke and kill lines, choke manifold, etc. to 250 psi low and 3,000 psi high. **NOTE: Make sure casing valve is open during all BOP tests.** After testing BOPs pick up 4 ½ tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and keep well dead.

9. RU 4 ½” rig hydraulic tubing tongs for handling of production tubing. Pick back up on tubing string and pull seal assembly from seal bore. Pull hanger to floor and remove same. Circulate bottoms up with packer fluid.

10. Pull out of hole (POOH) with tubing laying down same. **NOTE: Ensure well does not flow due to CO_2 “back flow”! Well condition is to be over-balanced at all times with at least 2 well control barriers in place at all times.**

Contingency: If unable to pull seal assembly RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. Several different sizes of cutters and pipe recovery tools should be on location due to possible tight spots in tubing.

11. If successful pulling seal assembly then pick up 3 ½ or 4 ½ inch workstring and TIH with QUANTUM packer retrieving tools. If tubing was cut in previous step then skip this step. Latch onto QUANTUM packer and pull out of hole laying down same. If unable to pull QUANTUM pull work string out of hole and proceed to next step. Assuming tubing can be pulled with packer with no issues, run CBL Adivser* cement bond log evaluation software or USI* ultrasonic imager to determine that there is no leakage around the wellbore above the caprock. If leakage is noted prepare cement remediation plan and execute during plugging operations. Set 9 5/8 inch cement retainer on wireline just in Eau Claire above the Mt Simon formation (approximately 5250 feet). Trip into hole with work string and sting into cement retainer. Test backside to 750 psi for 30 minutes on chart. A successful test should have less than 10% bleed off over the 30 minute period. This will be considered a successful casing test. Establish injection with packer kill fluid at 0.5, 1, and 2 BPM not to exceed 2,000 psi injection pressure. Sting out of retainer.

12. With pipe stung out of retainer, Mix and pump 300 (63 bbls) sacks of Class “H” cement mixed at 15.6 ppg plus fluid loss additive as proposed by cementing company and actual downhole conditions (temperature, BHP, etc). Obtain fluid loss of less than 100 cc/30 min. Follow that with 500 (105 bbls) sacks Class H cement mixed at 15.6 ppg with dispersant. Circulate to within 5 bbls of end of work/tubing string, sting into retainer and finish mixing cement. Displace tubing and squeeze away 30 bbls of cement into the open perforations.. Note: Do not squeeze at higher pressures than 2,000 psi. Sting out of retainer and reverse out a minimum of 2 pipe volumes. **Note: Leave cement on top of retainer.**

13. POOH racking back work string. Shut down for 12 hours Go in hole (GIH) open ended. Tag up on cement on top of retainer and note same.

14. Circ well and ensure well is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 175 sacks Class A or H). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 10 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. The following morning trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. Calculate volume for final plug. Pull tubing back out of well. Nipple down BOPs and cut all

casing strings below plow line (min 3 feet below ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug. Total of approximately 2660 sacks total cement used in all plugs. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 ft.

15. File all plugging forms to local state, federal and other agencies as required.

Note: utilize all local, state or federal rules relative to P&A or at least 33% plus actual volumes or as approved previously by Illinois state agency or Federal agency.

Table 3 - 7 Cost estimate for plugging and abandonment worst case scenario

Itemized P&A Costs	**Post Construction**[+]
a. Casing Evaluation: Mobilize equipment and crews from nearest district. Run multi-finger caliper for detailed inspection of the inner surface of the casing. Run Isolation Scanner for final condition of outer surface of casing and cement condition. Compare to baseline logs run before injection started.	\$50,000
b. Evaluation of any problems discovered by the casing evaluation: Downhole video camera to get visual images of the questionable inner surfaces of the casing.	\$20,000
c. Cost for repairing problems and cleanup of any groundwater or soil contamination: CO_2 as a vapor in soil would not result in contamination like a liquid. A formal “cleanup” may not be required, and the CO_2 would dissipate into the atmosphere. CO_2 into groundwater would like be the same as that in oil. For a period of time, the shallow groundwater may have a low concentration of CO_2 similar to a “flat” soft drink. With time the CO_2 will dissipate into the unsaturated soil and dissipate.	\$40,000
d. Cost for cementing or other materials used to plug the well:	\$78,000
e. Cost for labor, engineering, rig time, equipment and consultants:	\$157,000
f. Cost for decontamination of equipment:	N/A
g. Cost for disposal of any equipment: Tubing would be sold as scrap metal and worst case cost would be trucking services only.	\$2,000
h. Estimated sales tax: Our review shows there is no state sales tax for this kind of work.	\$2,000
i. Miscellaneous and minor contingencies (20%):	\$10,000
j. Total	\$359,000

[+] Post Construction cost is for 1/1/08; if the well was abandoned 30 years from now, assuming 3% annual inflation the worst case P&A would be 2.43 times greater or \$873,370.

3.2 VERIFICATION WELL

3.2.1 Westbay* Multilevel Groundwater Characterization and Monitoring System

The verification well was installed for the purpose of monitoring subsurface conditions and will not be used for injection of CO_2. One of the major research components of this project is to be able to establish the safe and secure storage of CO_2 in geologic subsurface environments. This requires implementation of multiple techniques to monitor the injection zone, shallow groundwater, soil and air. The monitoring data will be used to validate reservoir modeling used to predict the distribution of the CO_2. An outcome of this research will be to determine which monitoring methods work best for identifying CO_2 within the injection zone so that guidelines or recommendations can be developed for CO_2 monitoring. Another important part of the research is to validate that modeling and monitoring techniques are capable of predicting the movement of the CO_2.

One verification well has been drilled to observe the Mt. Simon through direct measurements of pressure and temperature, collection of samples for chemical analysis, and through wireline measurements. The monitoring well will provide an observation point for pressure and temperature measurements and fluid samples above the Eau Claire to evaluate caprock integrity. The Westbay system was deployed in the verification well to allow measurement of fluid pressures, collection of fluid samples, and performance of standard hydrogeologic tests at and between multiple intervals within a single borehole. A total of 11 monitoring zones were installed throughout the Mt. Simon injection horizon and the permeable stratigraphic units immediately overlying the caprock.

Westbay System Description

A Westbay system monitoring well is comprised of modular tubing, packers and valved port couplings. Fluid samples and in-situ fluid pressures are obtained using a wireline operated electronic probe that is lowered inside the tubing to access the monitoring zones via valved couplings. The Westbay system packers are made of Stainless Steel and a CO_2-resistant steel-reinforced inflatable sealing element. The packers are inflated singly and independently with water during the Westbay system installation process. The packers remain permanently inflated and sealed during all routine well operations. The packers are individually deflatable. There are two types of valved couplings in the system: measurement ports and pumping ports. Measurement ports are used where pressure measurements and fluid samples are required. Measurement ports incorporate a valve in the wall of the coupling which when opened by a probe provides a direct connection with the formation fluid. When not in operation the measurement port is always closed; this is verified by monitoring the water level inside the Westbay tubing (as described in section 4e.III.

Pumping ports are used where the injection or withdrawal of larger volumes of fluid is desired than would be reasonable through the smaller measurement port valve (such as for purging or for hydraulic conductivity testing of moderate to high hydraulic conductivity materials). Pumping ports incorporate a sliding sleeve which can be moved to expose or cover slots that allow formation fluid to pass through the wall of the coupling. A screen or slotted shroud is normally fastened around the coupling outside the slots. When not in operation the pumping port is always closed and this is verified by monitoring the water level inside the Westbay tubing. A removable plug may be placed at the bottom of the Westbay tubing string. This plug could then be removed to facilitate circulation or well control during any intervention required in the future.

System Operation

Fluid pressure measurements can be collected from each zone in the monitoring well. Pressures can be obtained periodically at each measurement port using a single pressure probe, or more frequently using a string of probes which remain in the monitoring well so that pressures can be recorded automatically at the well, and accessed periodically either at the well site or via remote communication.

MOSDAX Modular Subsurface Data Acquisition System*

This system, using a sampling probe, incorporates a pressure transducer so fluid pressure measurements can be obtained during each sampling event. Pressure measurements may also be collected from each isolated zone independently of sampling. Fluid samples can be obtained by lowering a sampling probe and sample container(s) to the desired measurement port coupling. The sampling probe operates in similar fashion to the pressure probe except that a formation brine sample is drawn through the measurement port coupling. Whenever the sampling probe is operated with the sampling valve closed, it functions the same as a pressure probe and supplies the same data.

When using a non-vented sample container, the fluid sample is maintained at formation pressure while the probe and container are returned to the top of the well. Once recovered, there are a variety of methods of handling the sample:

- the sample may be depressurized and decanted into alternate containers for storage and transport,

- the sample container may be sealed and transported (inside a DOT approved transport container) to a laboratory with the fluid maintained at formation pressure, or

- the sample may be transferred under pressure into alternate pressure containers for storage and transport.

The advantages of this discrete sampling method can be summarized as follows:

1) The sample is drawn directly from a measurement port immediately adjacent to the perforations. Therefore, there is no need for pumping a number of well volumes prior to collecting each sample. Because there is no pumping prior to sampling, the sample is obtained with minimal distortion of the natural formation water flow regime.

2) The lack of pumping means samples can be obtained quicker, even in relatively low permeability intervals.

3) The sample travels only a short distance into the sample container, typically from 1 to 2 ft, regardless of depth.

4) The risk and cost of storing and disposing of purge fluids is virtually eliminated.

3.2.2 Verification Well Casing, Cementing, and Completion

Figure 3-7 provides schematics showing subsurface and surface construction details of the verification well (Further further construction detail is available in the Verification Well completion report in Appendix G). The total depth of the well is 7272 ft (2216.5 m) below the rig kelly bushing (15 ft above the surface elevation). The surface elevation of the well is 669 ft (203.9 m) above MSL. The static water level in the well is 194 ft (59.1 m) above MSL. Table 3-8 below summarizes the bit sizes used for drilling and the corresponding depth interval where the bits were used. The surface casing was set at 377 ft, well below the lowermost USDW. The setting depth for the intermediate string is the top of the Eau Claire.

Table 3 - 8 Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0-377	17 ½	To bedrock
Intermediate	377-5,332	12 ¼	To primary seal
Long	5,332-7,272	8 ½	To TD

Each interval was drilled, cased, and cemented to surface. The casing for the surface and intermediate depths was steel, J55 (surface) and N80 (Intermediate). The long string was cased with J55 steel to 5,056 ft and 13Cr85 from 5,056 to 7,272. Tubing was run between 0 and 4,745 ft and the Westbay system was run between 4,745 and 7,128 ft. Based on joint strength the maximum allowable suspended weight of the tubing is 99,660 pounds and the actual weight of the tubing string in air is 30,843 lbs. The maximum allowable suspended weight of the Westbay is 22,000 pounds and the actual weight of the tubing string in air is 7,466 lbs. Table 3-9 provides additional detail on the casing and tubing used in the injection well.

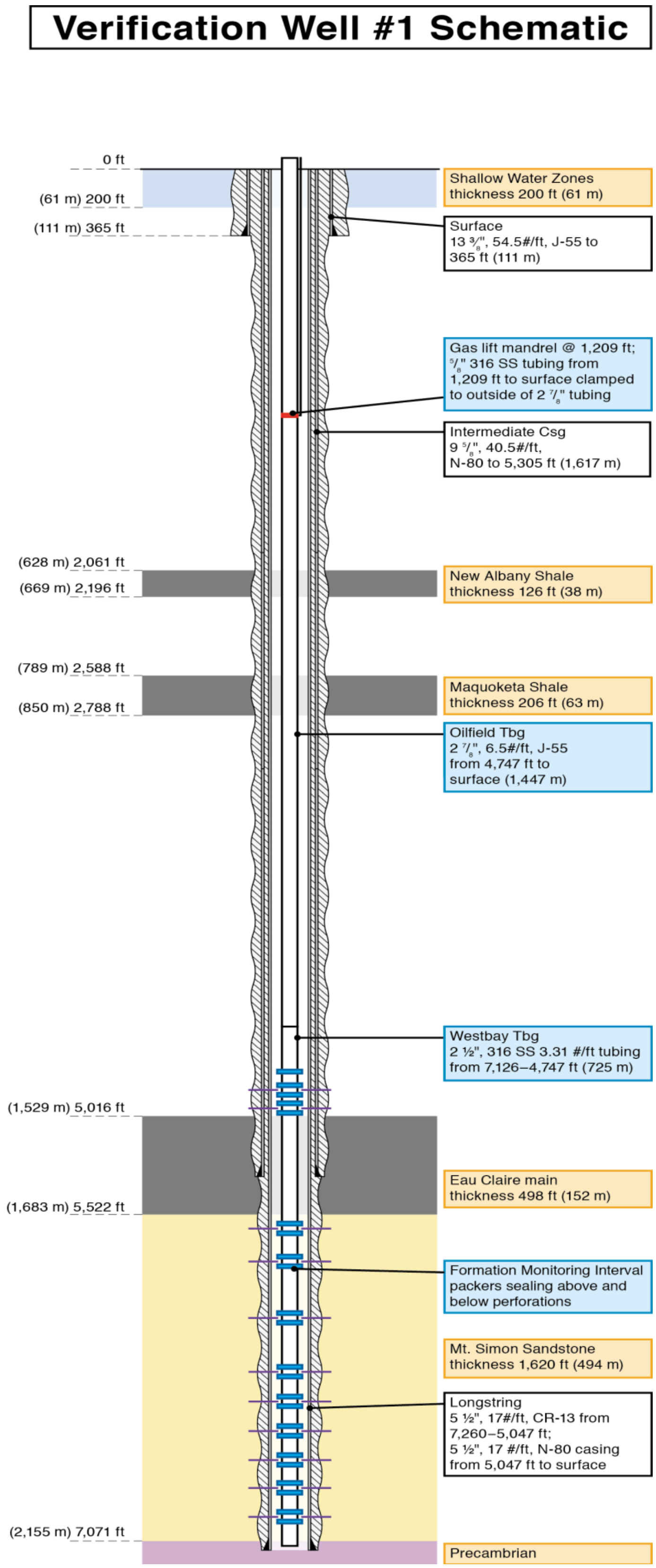


Figure 3 - 7 Verification well schematic

Table 3 - 9 Casing specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lbm/ft)	Grade (API)	Design Coupling	Coupling Outside Diameter (inches)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)
Surface	0-367	13 3/8	12.615	54.5	J55	STC	14 3/8	29.02
Intermediate	0-5,306	9 5/8	8.835	40	N80	LTC	10 5/8	29.02
Long (carbon)	0-5,056	5 1/2	4.892	17	J55	LTC	6.050	31
Long (chrome)	5,056 - 7,272	5 1/2	4.892	17	13Cr85	JFE BEAR	6.050	16
Tubing	0-4,745	2 7/8	2.44	6.5	J55	EUE	3.668	29.02
Westbay	4,745 – 7,128	2.5	2.26	3.12	316L SS	pin-up/box (captive nut) down, with proprietary Westbay/ACME thread	3.45	9.246

Cement

The well is fully cased and perforated for monitoring. All strings of casing are cemented to surface. The lower portion of the long string was cemented using the CO_2-resistant EverCRETE cementing system. The CO_2 resistant cement was placed from total depth through the Eau Claire formation and back into the intermediate casing. A conventional blend lead slurry was pumped ahead of the CO_2 resistant cement to fill the annular space between the intermediate and long string casings. The intermediate and surface strings were also cemented using conventional cement blends. Each of the cement formulations selected were appropriate for the expected well conditions including fluids and in the well. The surface casing and long string casing were cemented in a single stage. The intermediate casing was cemented in two stages.

EverCRETE CO_2-resistant cement was used to cement the bottom of the long-string over the entire open hole section from TD into the intermediate casing. The manufacturers specifications for EverCRETE are provided in Table 3-5. The final cementing program used is described in Table 3-10.

Table 3 - 10 Cement specifications for CCS #1

Casing	Depth Interval (feet)	Type/ Grade	Additives	Quantity (sacks)	Circulated to Surface	Thermal Conductivity (BTU/ft.hr. °F)
Surface (Lead)	0-377	Class A	Accelerator, LSCM	366	Yes	0.73
Surface (Tail)		Class A	Accelerator, LSCM	365	Yes	0.73
Intermediate-Sage 1 (Lead)	3,692-5,332	Class H	D047 Antifoam 0.020 gal/sk	353.4	Yes	0.54
Intermediate-Sage 1 (Tail)		Class H	D047 Antifoam 0.020 gal/sk	348.13	Yes	0.74
Intermediate-Sage 2 (Lead)	0-3,692	35/65 Class H-Pozzolan	D020 Extender 4.000%BWOB D044 Salt 10.000% BWOW, D065 Dispersant 0.350%BWOB D167 Fluid Loss 0.400%BWOB, D046 Antifoam 0.200%BWOB, D042 LCM/extender 5.000 lb/sk blend D079 Extender 0.400%BWOB	979.2	Yes	0.54
Intermediate-Sage 2 (Tail)		Class H	D047 Antifoam 0.020 gal/sk	99.57	Yes	0.74
Long (Lead)	0-4,950	35/65 Class H-Pozzolan	D020 Extender 6.000%BWOB D167 Fluid Loss 0.400%BWOB, D046 Antifoam 0.200%BWOB D153 Antisettling 0.300%BWOB	725.18	Yes	0.75

Casing	Depth Interval (feet)	Type/ Grade	Additives	Quantity (sacks)	Circulated to Surface	Thermal Conductivity (BTU/ft.hr. °F)
			D079 Extender 0.175%BWOB			
Long (Tail)	4,950-7272	EverCRETE CO2 Resistant Cement	D206 Antifoam 0.050 gal/sk blend D174 Expanding Cement Additive 10.000% BWOC D206 Antifoam 0.050 gal/sk blend D145A Dispersant 0.100 gal/sk blend D500 GASBLOCK LT 0.400 gal/sk blend D177 Retarder 0.020 gal/sk blend	800.71	Yes	0.75

Perforations and Monitoring Intervals

The Verification well was perforated in 11 zones using 3.5" PowerJet Omega* deep penetrating perforating shaped charge with 3106 HMX charges (Table 3-11) to allow monitoring in the Mt Simon and Eau Claire formations.

Table 3 - 11 Port numbers, perforation depths and number of perforations

Port No.	Perf Top (MD feet)	Perf Bottom (MD feet)	Formation Name	Shot Phasing (deg)	Total Shots
Z11 MP	4917.5	4920.5	Ironton-Galesville	60	18
Z 10 MP	5000.7	5003.7	Ironton-Galesville	60	18
Z 9 MP	5653.8	5657.3	Mt. Simon	120	11
Z 8 MP	5840.4	5843.9	Mt. Simon	120	11
Z 7 MP	6416.2	6419.7	Mt. Simon	120	11
Z 6 MP	6632.3	6635.8	Mt. Simon	120	11
Z 5 MP	6720.3	6723.8	Mt. Simon	120	11
Z 4 MP	6837.1	6840.6	Mt. Simon	120	11
Z 3 MP	6945.6	6949.1	Mt. Simon	120	11
Z 2 MP	6983.0	6986.5	Mt. Simon	120	11
Z 1 MP	7061.2	7064.2	Granite Wash	60	18

Annular Fluid

The only open annulus in the Verification well is the annulus between tubing (upper section)/Westbay (lower section) and the long-string casing. All of the annuli between casings or between casing and formation are cemented to surface. In the upper section of the annulus, the annulus between the casing and production tubing (Above the uppermost Westbay packer) the annulus contains 9.4 ppg NaCl brine with Nalco Adomite ASP 539D corrosion inhibitor at a concentration of 2 gallons per 1000 gallons brine.

In the Westbay section, monitoring intervals are perforated and open to the formation. They contain native formation brines, whose density varies slightly depending on the composition of the fluid. The Westbay quality assurance (QA) zones are not perforated and are isolated against the inner diameter of the long-string casing, they contain 9.4 lb/gal NaCl with adomite ASP 539D brine which was used during the installation of the completion system.

The brine occupying the annulus space between the final casing string and the 2-7/8-inch production tubing, and in the Westbay QA zones has a specific gravity of approximately 1.127 and a hydrostatic gradient of approximately 0.488 psi/ft.

Packers

There are a total of 28 Westbay MP55 packers in the Verification . Table 3-12 displays the setting depth of each individual packer.

Table 3 - 12 Packer depths

Packer No.	Top Depth (MD feet)	Packer No.	Top Depth (MD feet)
P28	4823.8	P14	5860.7
P27	4890.7	P13	6389.3
P26	4937.9	P12	6436.5
P25	4973.8	P11	6605.4
P24	5021.0	P10	6652.6
P23	5283.5	P9	6693.4
P22	5329.3	P8	6740.6
P21	5365.2	P7	6811.0
P20	5410.9	P6	6858.2
P19	5456.6	P5	6918.7
P18	5502.4	P4	6956.1
P17	5627.0	P3	7003.3
P16	5674.2	P2	7034.2
P15	5813.5	P1	7081.4

The packers in the completion assembly are Westbay Steel MP55 System MP55 Packer – 90mm Element Part No. 0414100C4. The Westbay packers can be described as steel-reinforced, rubber gland inflatable packers. The packers were inflated with tap water in sequence beginning with the deepest. All of the packers were inflated normally with the exception of packers P24 and P26. Packer P24 is positioned below Zone 10 and packer P26 is positioned below Zone 11. During the operation, inflation diagnostics indicated that these two particular packers were not able to maintain the appropriate inflation pressure. These two packers are judged to be uninflated. In each case, the subject packer provided redundancy as part of a 2-packer set designed to seal inside the casing between two perforated intervals. The second packer of each set (packer P23 and packer P25, respectively) inflated normally and all standard monitoring operations of the well are un-affected.

Fluid Spotting

After the 5 ½-inch long-string casing was cemented in place, it was filled with a 9.2 lb/gal (0.477 psi/ft equivalent hydrostatic gradient) NaCl completion brine, which was of sufficient density to control fluid movement into the wellbore from open perforations and throughout the installation of the Westbay monitoring system. The maximum reservoir pressure gradient calculated from surface was approximately 0.45 psi/ft, as determined from reservoir pressure measurements acquired during open-hole logging. Prior to installing the Westbay system in the well, 65 barrels of 9.4 ppg sodium chloride brine, with Nalco Adomite ASP 539D corrosion inhibitor at a concentration of 2 gallons per 1000 gallons of brine, were spotted from TD back to 4500 feet.

After the Westbay system was installed and all but the shallowest Westbay packer (P28) was inflated, the pumping port sliding sleeve of QA Zone 16 was opened and the annulus was flushed with approximately 20 bbls of 9.2 lb/gal brine which was circulated through the tubing. This mixture was then replaced with 27.8 bbls of 9.4 lb/gal sodium chloride brine with Nalco Adomite ASP 539D corrosion inhibitor at a concentration of 2 gallons per 1000 gallons of brine. Afterwards, the sliding sleeve in QA Zone 16 was closed and the shallowest packer (P28) was inflated properly, thereby isolating the annular space to surface.

3.2.3 Well Drilling, Testing, and Logging

The well was drilled with a rotary-table drilling rig with a water-based circulating mud system by Pioneer Oil Field Services of Vincennes, IN. No well stimulation was conducted. A variety of wireline logs and tests were conducted during each stage of drilling and completing the well; the types of logs and tests run are listed below with detailed information included in Appendix G.

Logging During Drilling

Surface Hole:

- Wireline Logs:
    - Laterolog-GR-SP

Intermediate Hole:

- Wireline Logs:
    - Neutron-Density-GR Combo

- Laterolog Resistivity
- FMI* fullbore formation microimager
- ECS* elemental capture spectroscopy sonde Natural Gamma Ray Spectroscopy
- MDT* modular formation dynamics tester
- Rotary Sidewall Cores
- SP

Final Hole:

- Wireline Logs:
  - Neutron-Density-GR Combo Laterolog Resistivity
  - Induction Resistivity
  - Micrologs
  - FMI
  - Sonic Scanner* acoustic scanning platform
  - ECS
  - Natural Gamma Ray Spectroscopy
  - CMR200* combinable magnetic resonance tool
  - Rotary Sidewall Cores
  - Formation Pressures
- Conventional Whole Core:

Table 3 - 13 Whole Core Intervals (uncorrected driller's depths).

Hole Section (in)	Formation Name	Length (ft)	Est. Top of Formation (ft)	Core Top (ft)	Core Bottom (ft)
12-1/4	New Albany	27	2071	2132	2159
12-1/4	Knox (Gunter-Eminence transition)	46	4238	4218	4264
12-1/4	Knox (Potosi)	46	4344	4513	4559
8-1/2	Eau Claire-Mt Simon transition	139	5017	5425	5564
8-1/2	Mt. Simon	60	5515	5930	5990
8-1/2	Lower Mt. Simon	389	5515	6680	7069

Logging During and After Casing Installation

Surface Hole:

- Wireline Logs:
  - Cement Bond Log with Variable Density Log (CBL-VDL)

Intermediate Hole:

- Wireline Logs:
  - Ultrasonic Cement Imaging
  - Cement Bond Log with Variable Density Log (CBL-VDL)

Final Hole:

- Wireline Logs:
  - Isolation Scanner Image Log
  - Cement Bond Log with Variable Density Log (CBL-VDL)
  - Pressure/Temperature Log
  - Thermal Neutron Decay (Formation Sigma) Log (RST)
  - Multi-finger Casing Caliper Log (PMIT)
  - Casing Collar and Perforating Record Logs
  - Pressure/Temperature Log (Run 2)

The baseline logs indicate that the Verification well provides hydraulic isolation between zones. The CBL on the surface string of casing shows that from 253 to 262 ft. and at 189 ft. the amplitude measures just under 2 mv. This translates into an attenuation of 9.2 dB/ft. Using this value to compute the compressive strength of the cement at this interval, a value of approximately 2000 psi is obtained and the interval is believed to be a 100% bonded interval. To demonstrate zone isolation it is desirable to have a continuous interval with the attenuation greater than 6 dB/ft. The attenuation is greater than 6 dB/ft from 253 to 262 ft., from 232 to 226 ft., and a total of 15 ft. between 212 ft. and 184 ft. Ideally it would be preferred that the cement were more continuous. However, there are several additional considerations. There are also several other intervals in the well have attenuations in the 4 to 6 dB/ft range where cement is certainly present. Also, it is known that cement was circulated to surface and that the cementing job was executed according to plan with no observed fallback even though the CBL does not indicate the presence of cement above 148 ft. Given this information it is believed that the CBL is showing good hydraulic isolation in the zones mentioned and a sufficient amount of cement behind the casing up to 148 ft. This volume is sufficient to prevent any fluids from flowing from below in to any USDW behind the casing in this interval as is the objective of this casing string.

The USIT log also shows that the casing has no internal or external defects at this time based on the internal radius and thickness measurements.

The production string of casing was also determined to have good hydraulic isolation over most of the length of the casing, with only short intervals where there are isolated pockets of fluid and not cement behind the casing. The top of the injection zone is 5520 ft. and the first of these intervals below this point that has any potential to flow fluids is a very short interval from 5564 to 5570 ft. It is actually more likely that this zone has a thin cement sheath rather than a channel. The casing below this point is all considered to be 100% bonded with good hydraulic isolation. Above the base of the confining layer the first potential channel would be from 4314 to 4306 ft. Therefore, there is no potential for any fluids to migrate from the injection zone to zones above the confining layer by way of the casing-formation annulus. The acoustic impedance image of the USIT clearly shows the change in acoustic impedance for the two different cement types used while cementing this string of casing. This change occurs at about 4900 ft, indicating that the CO_2 resistant cement was brought up into the annulus of the long string and the intermediate string of casing.

The USIT part of the Isolation Scanner and the PMIT also show that the casing has no internal or external defects at this time based on the internal radius and thickness measurements. The PMIT was run after the casing was perforated in the zones to be monitored by the Westbay system, and these perforations can be seen on the log. The perforations were not considered as defects as the holes were intentional and part of the completion. Appendix F (ADM Verification Well #1 Mechanical Integrity Log and Testing Descriptive Report) provides additional detail on the Verification well log analyses.

3.2.4 Demonstration of Mechanical Integrity Prior to Operation

Once the appropriate completion fluid was spotted in this annular space, the mechanical integrity was verified via a positive pressure test conducted on June 10, 2011 and witnessed by IEPA Regional Geologist, Jeff Turner, P.G. During the test, the annulus was pressurized to approximately 317 psig and, once stabilized it demonstrated less than 1 psig leak-off during the hour-long observation period. The leak-off was less than the prescribed maximum leak-off criteria of 3% (Appendix G for a plot of the results of the Mechanical Integrity Pressure Test). During the life of the well this same annulus will be pressure tested to at least 200 psig on an annual basis with a maximum of 3% leakoff allowed, as per the IEPA Class I non-hazardous UIC permit requirements.

In addition to demonstrating the mechanical integrity of the tubing-casing annulus, the integrity of the entire Westbay system was confirmed through a negative-pressure test. As per the IEPA Class I non-hazardous UIC permit requirements, the sealed Westbay completion assembly was to be tested to at least a 100 psi differential pressure to demonstrate no more than 3% leak-off over a one hour period. The test was conducted over approximately 20 hours from June 13 to June 14, 2011. In order to conduct the under balance test, the hydrostatic column in the well was reduced via nitrogen gas-lift through the gas-lift mandrel installed in the completion tubing at a depth of 1208 feet KB. The fluid column was successfully lowered to a depth of 1097 feet KB. A Westbay measurement probe was positioned at a depth of approximately 1550 feet KB in order to monitor the pressure throughout the test. The effective pressure under balance across the Westbay tubing at the position of the measurement probe was estimated to be 535 psi and should have been of a comparable magnitude throughout the rest of the column. Over the length of the test, the pressure was observed to change from 222.2 to 223.3 (1.1 psi), or less than 0.5% of the measured value. A plot of the results of the interior tubing test is included in Appendix G.

The zonal isolation between the Westbay packers was verified in the monitoring and QA zones using a pre- and post-inflation pressure profile. A plot of the pre- and post-inflation pressure profiles is included in Appendix G. The pre-inflation profile reflects the hydraulic head between the monitoring and QA zones when there is no zonal isolation; therefore, the pressure at each measurement point can be observed to lie along a common pressure gradient line. As each subsequent packer is inflated and as each zone is isolated (from deepest to shallowest), the hydrostatic influence of the underlying zone(s) is removed. Therefore, differences between the pre- and post-inflation pressure profiles provide confidence that, in fact, the packers are effectively isolating hydrostatic communication between each zone.

3.2.5 Well Compatibility

The verification well will not inject CO_2 however it is anticipated that it may come in contact with CO_2 from the nearby injection well. The compatibility of the Verification well with the injection zone fluid, injection zone formation minerals, and confining zone minerals is the same as that of the injection well and is covered above in Section 3.1.3.

Westbay Tubing

The only place the Westbay tubing may come in contact with the CO_2 is at the perforated intervals. However, the Westbay system is constructed using stainless steel components that are resistant to corrosion from exposure to CO_2-brine mixtures and no compatibility issues are expected.

Long String Casing

The portion of the long string casing installed from total depth of the well past the base of the confining layer (to a depth of 5056') is composed of chrome-steel (13CR85) and is specifically engineered to function in environments with high concentrations of CO_2. The long string casing in the remainder of the well (5056' to surface) is carbon steel. However this section is protected from CO_2 exposure by cement and the intermediate casing and exposure and thus reactivity between the injected CO_2 and the long string casing is expected to be negligible.

Cement

The long string casing is encased from total depth to approximately 4950 feet (or approximately 370 feet into the intermediate casing string) in the Schlumberger proprietary blend of CO_2-resistant cement, EverCRETE. The EverCRETE portion of the sheath will act as a barrier to CO_2 traveling up the backside of the casing and reaching the non-CO_2 resistant cements. Changes in the cement due to reaction between the injected CO_2 and the cement is expected to negligible.

Annular Fluid

Reactivity between the injected CO_2 and the annular fluid, 9.4 lb/gal sodium chloride brine with Nalco Adomite ASP 539D corrosion inhibitor is expected to be negligible.

Packers

The packers installed are a Westbay MP55 are manufactured from 316/316L stainless steel and incorporate a reinforced rubber gland made of Hydrogenated Nitrile Butadiene Rubber (HNBR) and a pressure balanced inflation/deflation valve mounted on a stainless steel mandrel. The Westbay MP55 packers are CO_2 resistant and as a result will not be impacted by the injected CO_2.

Well Head Equipment

The wellhead and wellhead equipment are isolated by the Westbay completion and will not be in contact with the injected CO_2; therefore, no adverse reactions are expected between the injected CO_2 and any of the wellhead components.

Holding Tank(s) and Flow Lines

Verification Well #1 is not used for injection and therefore will not possess holding tanks and flow lines for CO_2 injection.

3.2.6 Westbay Monitoring Equipment

Details of the various process monitoring sensors and gauges are summarized below and include the location of the device, the brand and model number, the device type (electrical or mechanical), and whether or not the device is continuously recording.

Pressure Monitoring Gauge(s)

Surface Pressure Gauge:

Location: Installed directly into the Verification Well #1 wellhead tree cap port.

Make / Model: ABB Model 266GSH-U

Type: Electrical; Continuous Recording

Operating Range: 0 – 435 (psig); this exceeds maximum operating range of system by more than 20%

Downhole Pressure Gauges:

Location: There are a total of 11 measuring ports and 1 QA/QC port in the well as displayed below in Table 3-14.

Table 3 - 14 Measurement Port Depths

Measurement Port	Depth	Measurement Port	Depth
1	7060.6	7	6415.6
2	6982.4	8	5839.8
3	6945.0	9	5653.3
4	6837.3	QA/QC	5482.0
5	6719.7	10	5001.1
6	6631.7	11	4917.0

Make / Model: Westbay MOSDAX System Pressure/Temperature Probe Model 2580

Type: Electrical; Continuous Recording

Operating Range: 0 – 5,000 (psig); this exceeds maximum operating range of the system by more than 20%. Pressure accuracy: ± 0.1% FS (CHRNL)

Casing-Tubing Annular Pressure Gauge(s)

For additional details on the Annulus Protection System, refer to the description included as Appendix G.

Surface Pressure Gauge:

Location: Mounted on the Verification Well #1 wellhead port open to the casing-tubing annulus.

Make / Model: ABB Model 266GSH-U

Type: Electrical; Continuous Recording

Operating Range: -15 – 435 (psig); this exceeds maximum operating range of system by more than 20%

Temperature Gauges

Downhole Temperature Gauges:

Location: There are a total of 11 measuring ports and 1 QA/QC port in the well as displayed above inTable 3-14.

Make / Model: Westbay MOSDAX System Pressure/Temperature Probe Model 2580

Type: Electrical; Continuous Recording

Operating Range (degF): 32 to 158; this exceeds maximum operating range of system by more than 20%Plugging and Abandonment

Removal of subsurface well features

Casing: All casing used in this well has been cemented to surface and will not be retrievable at abandonment after injection.

Tubing and Packers: The Westbay packers will be deflated and the tubing string removed. If the packers cannot be released and removed from the cased hole, a determination will be made as to where in the well the pipe is stuck and an electric line with tubing cutter will be used to cutoff the tubing above the lowest stuck packer.

Plug Placement Method: The **Balanced Plug** placement method will be used. This is a basic plug spotting process that is generally considered more efficient and is consistent with best industry practices.

Type and quantity of plugging materials, depth intervals: In addition to the proper volumes, placement of plugs on depths approved by the permits (the minimum requirements), all cement will be previously tested in the lab, a CemCADE* cementing design and evaluation software will be run using actual well information such as actual depth, temperature on bottom, hole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug. All casing is cemented to surface and no casing will be retrieved. From the surface, at least 3 feet of all the casing strings will be cutoff well below the plow line and a blanking plate with the required permit information will be welded to the top of the cutoff casing.

Detailed plugging and abandonment procedures

Notifications, Permits, and Inspections (Prior to Workover or Rig Movement) Notifications, Permits, and Inspections are the same for plug and abandonment during construction and post-injection.

1. Notify EPA 48 hours prior to commencing operations. Insure proper notifications have been given to all regulatory agencies for rig move.

2. Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and ADM has written permission to proceed with planned ultimate P&A procedure.

3. Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks, and ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.

4. Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.

5. Make sure all operations have been planned and are carried out in such a manner that meets appropriate standards.

Volume Calculations

Estimated volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1. Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2. Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

3. See generic calculations in the well plugging plan in Section 8. Have cementer and wellsite supervisor both review calculations prior to spotting any plug.

Note: For each cementing operation the cementer and the wellsite supervisor will verify via a cementing handbook or iHandbook all calculations and have ADM approve the manner and procedure for cementing operations. Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

Possible Plugging and Abandonment Procedure

At the end of the serviceable life of the verification well, the well will be plugged and abandoned.

In summary, the plugging procedure will consist of removing all components of the completion system and then spotting cement plugs along the entire length of the well. At the surface the well head will be removed and casing cut off 3 feet below surface. A detailed procedure follows:

1. Move in workover unit with pump and tank.

2. Fill both tubing and annulus with kill weight brine.

3. Nipple down well head and nipple up BOPs

4. Remove all downhole equipment from well

5. Keep hole full with workover brine of sufficient density to maintain well control

6. Pick up 2 7/8” tbg work string (or comparable) and trip in hole to PBTD

7. Circulate hole two revolutions to ensure that uniform density fluid is in the well

8. Start setting cement plugs by spotting 56 sacks Class A cement with 1% TIC. This amount is equal to 500 ft in the 5 ½” casing. Pull 10 stands (20 joints) tbg and reverse circulate hole for two tbg volumes. Lay down tubing as it is pulled from well.

9. Repeat plug setting procedure until uppermost set of perforations is covered. Reverse circulate hole one revolution.

10. Pull ten stands and shut down overnight.

11. On the next morning TIH ten stands and tag plug. Resume plugging procedure as before and continue spotting plugs until the last plug at the surface. Repeat until last plug at surface and spot the appropriate volume of cement to reach surface.

12. Nipple down BOPs

13. Cut off all well head components and cut off all casings at below ground level.

14. Finish filling well with cement.

15. Install permanent marker back to surface on which all pertinent well information is inscribed.

16. Fill cellar with topsoil.

17. Rig down workover unit and move out all equipment. Haul off all workover fluids to proper disposal site.

18. Reclaim surface to normal grade and reseed location. 7,500 ft 5 ½” 15.5 #/ft casing requires 850 sks cement to fill, 25 plugs (estimated) Approximately five days required from move in to move out, depending on the operations at hand and the physical constraints of the well, weather, etc..

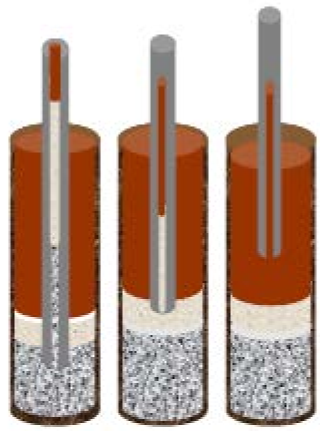


Figure 3 - 8 Schematic of pumping the cement job using the balanced plug method.

The mottled grey is cement, the white is spacer, and the brown is mud. In the first graphic, the first spacer has already been pumped, and they are pumping in the cement. In the 2nd graphic, they have displaced most of the cement (don't want to contaminate the cement, so leave a little in pipe at this stage), pulled the end of the pipe up into the space, and are displacing the end of the cement and putting more spacer fluid in between the mud and the cement. In the 3rd graphic, they are circulating mud to clean the pipe and casing of any cement before it sets.

2009 Cost estimate for Plugging and Abandonment Worst Case Scenario

a. Casing Evaluation: Mobilize equipment and crews from nearest district. Run multi-finger caliper for detailed inspection of the inner surface of the casing. Run Isolation Scanner for final condition of outer surface of casing and cement condition. Compare to baseline logs run before injection started. N/A $50,000

b. Evaluation of any problems discovered by the casing evaluation: Downhole video camera to get visual images of the questionable inner surfaces of the casing. N/A $20,000

c. Cost for repairing problems and cleanup of any groundwater or soil contamination: CO_2 as a vapor in soil will not result in contamination like a liquid. A formal “cleanup” may not be required, and the CO_2 will dissipate into the atmosphere. CO_2 into groundwater will like be the same as that in oil. For a period of time, the shallow groundwater may have a low concentration of CO_2 similar to a “flat” soft drink. With time the CO_2 will dissipate into the unsaturated soil and dissipate. N/A $40,000

d. Cost for cementing or other materials used to plug the well: $37,000 $37,000

e. Cost for labor, engineering, rig time, equipment and consultants: $157,000 $157,000

f. Cost for decontamination of equipment: N/A N/A

g. Cost for disposal of any equipment: Tubing will be sold as scrap metal and worst case cost will be trucking services only. N/A $2,000

h. Estimated sales tax: Our review shows there is no state sales tax for this kind of work. $2,000 $2,000

i. Miscellaneous and minor contingencies (20%): $10,000 $10,000

j. Total $206,000 $318,000

$^{+}$Post Construction cost is for 1/1/10; if the well was abandoned 30 years from now, assuming 3% annual inflation the worst case P&A would be 2.43 times greater or $772,740.

3.3 GEOPHYSICAL MONITORING WELL

3.3.1 Location

The geophone well was drilled to 3,500 ft. A map showing well with respect to the facility boundaries is provided as Figure 3-1. The location of the well is summarized below:

Township-Range-Section: 390 feet(118.87m) south and 185 feet (56.39m) west of the NE corner of the NW corner of the NW corner of Sec 5, T16N, R3E; Macon County, Illinois
Local Latitude: 39.87704081
Local Longitude: -88.89395539
Surface Elevation: 675ft (205.74m) KB 15 (4.57m) ft above GL
Well Depth: 3500ft (1066.8m)

3.3.2 Geophone Well Casing, Cementing, and Completion

Drilling operations on this well were started on Oct. 29, 2009 and finished on November 11, 2009. The well was drilled using Pioneer Drilling Rig # 15 and was rotary mud drilled.
The well driller used for construction of this well was:

Pioneer Drilling Rig 15
Rt 4, Box 142 B
Lawrenceville, Il 62439

Surface casing was set to 349 ft and cemented back to surface. An 8.5 inch hole was drilled to 3500 ft into the top of the Shakopee shale. No cores or DSTs were taken but a suite of open hole logs were run. A 31 level geophone array was installed in the well via a string of 3 ½ inch tubing that was used as casing. The geophone array attached to the outside of the 3 ½ inch pipe was then cemented in place with cement returned to surface. Operations were suspended until all necessary trenching and cabling could be installed and connected to a data acquisition system on site. In early February a cement bond log was run showing excellent cement to surface. The array was tested and found to be working well. Testing continued until mid February and system was permanently connected to data acquisition system. The array was then used in obtaining VSP data at the wellsite. The system is continuously recording seismic events at the present. Figure 3-9 provides a schematic showing subsurface construction details of the geophone well (Further further construction detail is available in the Geophone Well completion report in Appendix H.)

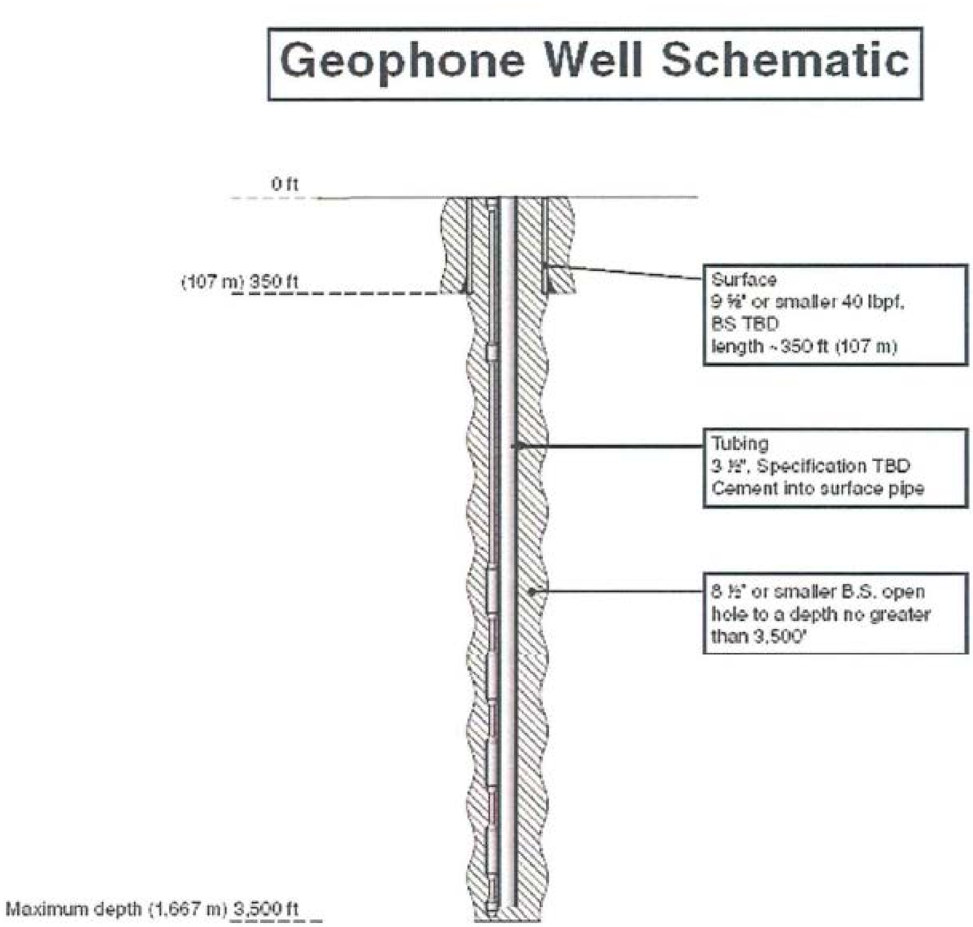


Figure 3 - 9 Geophone Well Schematic

Table 3 - 15 Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0-351	12 ¼	To bedrock
Long	351-3,500	8 ½	To TD

Each interval that was drilled was cased and cemented to surface. The surface casing was N80 steel. The long string was cased with L-80 tubing run as casing to support the geophone array. Table 3-17 provides additional detail on the casing and tubing used in the injection well.

Table 3 - 16 Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lbm/ft)	Grade (API)	Design Coupling	Coupling Outside Diameter (inches)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)
Surface	0-349	9 5/8	8.835	40	N80	LTC	10.625	29.02
Long	0-3,500	3 1/2	2.992	9.3	L80	8 Round EUE	4.5	29.02

Cement

The well is fully cased and perforated for monitoring. All strings of casing are cemented to surface. The final cementing program used is described in Table 3-18.

Table 3 - 17 Cement specifications for the geophysical monitoring well

Casing	Depth Interval (feet)	Type/ Grade	Additives	Quantity (Sacks)	Yield (ft^3/sack)	Density (ppg)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)	Circulated to Surface
Surface	0-349	Class A	2% $CaCl_2$ 0.25 lb/sk Flakes	200	1.19	15.8	0.73	Yes
Long string	0-3,500	Franklin 10/10 FSS	0.2% C-13 Retarder, 0.125 lb/sk Flakes	920	1.63	14.2	0.6	Yes

3.3.3 Logging

During Drilling

Prior to setting casing the hole was logged with multiple tools to fully characterize the formations in the gologic column. The open-hole login suite for the final hole is described below.

Final Hole:

Wireline Logs:
- Drilling Log
- Laterolog

SP
Micro Resistivity
Gamma Ray
Compensated Neutron
Litho Density
Caliper
Directional Survey

During and After Casing Installation

After casing and cementing the wells were logged to ensure the integrity of the cement job. The logs that were run are described below:

Final Hole:
- Wireline Logs:
  - Ultrasonic Cement Imaging Log
  - Variable Density Cement Bond Log
  - Pressure/Temperature Log
  - Casing Collar Logs
  - Gamma Ray Log

3.3.4 Well Abandonment

At the end of the serviceable life of the well, the well will be plugged and abandoned utilizing the following procedure:

1. Notify EPA of abandonment at least 24 hours prior to plugging the well.

2. Cement may be circulated from total depth or plugged-back total depth to surface or cement plugs may be placed as specified below.
   a. Cement plug circulated or dump bailed over any perforated interval (none planned).

   b. Cement plug circulated inside casing from 500' to a minimum of 250'

3. Cut off all well head components and cut off all casings below ground level.

4. Finish filling well with cement.

5. Install permanent marker at surface.

3.4 REFERENCES

Bethke, C.M.. 2006. The Geochemist's Workbench (Release 6.0) Reference Manual. RockWare, Inc., Golden CO, 240 p.

Berger, P.M., Mehnert, E., and Roy, W.R. (2009) Geochemical Modeling of Carbon Sequestration in the Mt. Simon Sandstone. Geological Society of America *Abstracts with Programs*, vol. 41, no. 4, p. 4.

Bourgoyne, A.T. Jr., Scott, S.L., Regg, J.B., 1999, "Sustained Casing Pressure in Offshore Producing Wells",OTC (SPE) Paper 11029

Buckwalter, J.F. 1951. "Selection of Pressure Water Flooding Various Reservoirs", Drilling and Production Practice, American Petroleum Institute.

Dickey, P.A. and Andresen K.H. 1946. "Selection of Pressure Water Flooding Various Reservoirs," Drilling and Production Practice, American Petroleum Institute.

Goodwin, K.J., and Crook, R.J., 1992, "Cement Sheath Stress Failure", SPE Paper 20453

Frommelt, D., 2010. Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, Archer Daniels Midland Company – UIC Permit UIC-012-ADM, dated May 5, 2010.

Howard, G. C. and C.R. Fast. 1970. Hydraulic Fracturing, New York Society of Petroleum Engineers of AIME, 210 p.

Robinson, J. 2003. Personal communication, Franklin Well Services, Lawrenceville, Illinois.

Sabins, F., 2004, "MMS Project: Long-Term Integrity of Deepwater Cement Systems Under Stress/Compaction Conditions, Summary Report," http://www.boemre.gov/tarprojects/426.htm

Teodoriu, C., Reinicke, K.M., Fitcher, C., Wehling, P., 2010, "Investigations on casing-cement interaction with applications to gas and CO2 storage wells," SPE Paper 131336

4 OPERATION PROGRAM AND SURFACE SYSTEM

4.1 WELL INFORMATION

The injection well is named CCS #1. The verification well is named Verification Well #1, and the geophysical monitoring well is named Geophysical Monitor Well #1.

4.1.1 Location

Injection well CCS #1is located at:

Section 32, Township 17N, Range 3E of 3rd Principal Meridian.

Latitude: N 39° 53' 8" (N 39.88577°)

Longitude: W 88° 53' 19" (W 88.88883°)

4.1.2 Expected Service Life

Based on the construction materials and construction techniques (Section 3.1.2), the expected service life of the well is 30 years. However, only 3 of years injection are currently planned.

4.1.3 Injection Rate, Average and Maximum

The compression and dehydration system is designed for a normal operating capacity of 1,100 metric tons (MT) per day with a maximum operating capacity of 1,200 MT per day. A custody transfer flow measurement device has been installed on the CO_2 transmission pipeline between compression and dehydration facility and the injection wellhead. The flow meter will produce a direct reading of total amount of injected CO_2 in units of mass per unit of time. The average injection rate will be 1,000 MT per day over the project's 3-year injection-period. Over the life of the project, one-million MT of CO_2 will be injected into the Mt. Simon Sandstone.

4.1.4 Anticipated Total Number of Injection Wells Required

The CCS #1 injection well is the only injection well that will be used for the IBDP project. There is another injection well – the ICCS injection well, CCS #2 – being planned for the ADM site. However, this well (CCS #2) is not part of the proposed IBDP project.

Over the next several years, ADM plans to operate two injection wells for a period of time. The injection scenario starts with CO_2 injection for 1 year at 1,000 MT/day into CCS#1. This will be followed by 2 years of dual injection – 1,000 MT/day into CCS #1 and 2,000 MT/day into CCS #2. After the dual-injection period there will be 3 years of injection into CCS #2 at 3,000 MT/day with CCS #1 shut-in.

4.1.5 Number of Injection Zone Monitoring Wells

There is one injection-zone monitoring well (Verification Well #1) within approximately 1,000 feet north-northwest of the injection well (CCS #1). This well will verify the location of the CO_2 within the Mt. Simon and monitor the overlying zones. Details regarding the verification well design and construction are included in Section 3.2.2. A geophysical (geophone) monitoring well (Geophysical Monitor Well #1) will provide geophysical monitoring of the CO_2 plume. Details regarding the geophysical well design and construction are included in Section 3.3.2. Schematics of the injection, verification, and geophysical wells are provided as Figure 4-1.

4.1.6 Injection Well Operating Hours

The injection well will operate continuously (24 hour per day, 7 days a week, and 365 days per year) during the permit period. The injection rate will vary between 0 and 1,200 MT per day for equipment maintenance, mechanical inspection, and testing, and during startup and shutdown procedures.

4.1.7 Injection Pressure, Average and Maximum

The operational injection pressure is estimated to be between 1,400 and 1,950 psi with a maximum injection pressure of 1,950 psi. Pressure may be lower than the above range due to high injectivity of the reservoir.

4.1.8 Casing/Tubing Annulus Pressure, Average and Maximum

The only uncemented annulus in the well is the annulus between the tubing and the long-string casing. The injection tubing is set in a packer above the injection interval within the Mt. Simon. The packer isolates the casing-tubing annular space from the CO_2 stream. A constant surface annulus pressure of 400 or greater will be kept on the annulus during injection. Fluctuations in pressure are anticipated due to changes in ambient surface temperature, injection tubing pressure, and injection tubing temperature, and volume of carbon dioxide at temperatures dependent upon equipment operation (i.e., if one compressor is off line). The annular space and annular pressure system is completely described in Section 3.1.2.

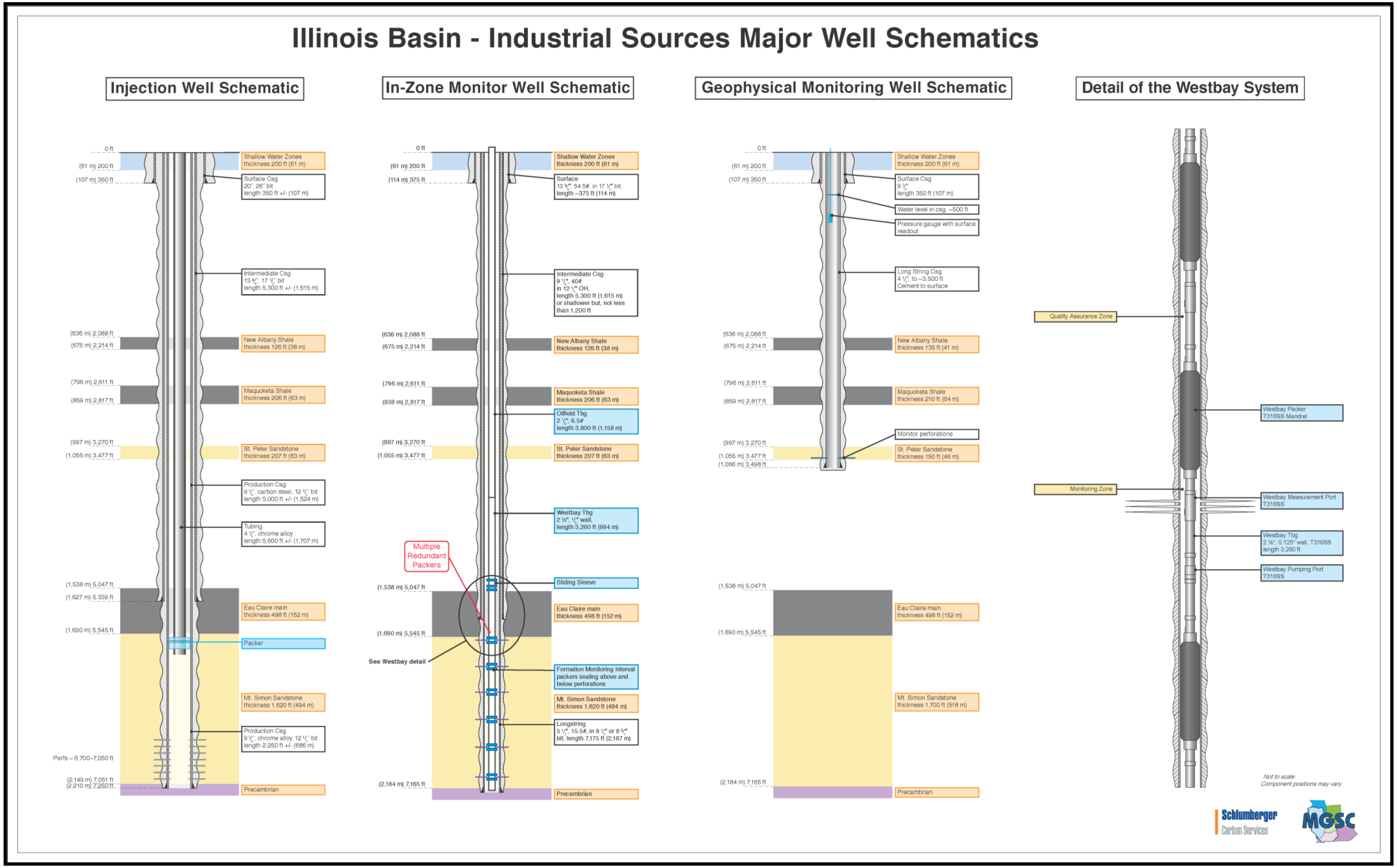


Figure 4 - 1 Schematic of Injection Well, Monitoring (Verification) Well, Geophysical (Geophone) Well, and Detail of Monitoring System (Westbay System).

Note: Packer location within the injection well will be set at a depth that will allow for the maximum CO_2 injection rate of 3,300 MT/day.

4.2 SURFACE SYSTEM

4.2.1 Injection Fluid Storage

There is no intermediate storage of injection fluid. The CO_2 for this project is produced continuously from the ethanol production facility and is vented to the atmosphere if the injection well is not in operation.

4.2.2 Holding Tanks and Flow Lines

There are no holding tanks for the injection fluid. The flow line from the compression and dehydration facility to the injection site is made of 6-inch diameter API 5L X52 schedule 40 carbon steel pipe and is approximately 6400 feet long.

4.2.3 Process Flow Diagrams and Process Description

The Surface System for the Midwest Geological Sequestration Consortium Phase III project includes compression and dehydration equipment that takes a water-saturated CO_2 gas stream from an ethanol plant wet scrubber discharge at approximately 90 °F and 0.5 psig and compresses the CO_2 to pressures up to 2000 psig. Gas is also dehydrated to typical CO_2 pipeline concentrations of ≤ 30 lb/MMSCF or 630 ppmv at an intermediate step in the compression process. The compression and dehydration equipment is located east of the ethanol fermentors in the Corn Processing Facility. Compressed, dehydrated CO_2 at rates up to 1100 metric tons/ day (21 MMSCFD) can be delivered to the pipeline at pressures ranging from 1400 to 1950 psig and temperatures ranging from approximately 60 to 120 °F. CO_2 travels through the approximately 6400 feet of 6-inch diameter Schedule 40 pipe from the Surface System to the injection well. Instrumentation to measure and record key operating pressures, temperatures, flow rates and other process parameters is also included with the Surface System.

The Process Control Strategy Diagrams (PCSDs) for the Surface System are shown in Figures 4-2 and 4-3.

The equipment consists of a single 1250 hp centrifugal booster blower that raises pressure to approximately 17 psig, followed by two parallel 3250 hp 4-stage reciprocating compressors that boost the pressure to 1400 psig, a dehydration unit, and a 200 hp multistage centrifugal pump that boosts the pressure to up to 1950 psig. Use of the pump is optional depending on pressure response of the reservoir. Triethylene glycol dehydration is performed between the third and fourth stages of the reciprocating compressors, where water content in the CO_2 is at a minimum due to previous compression and cooling steps. Shell and tube heat exchangers using cooling water remove the heat of compression following each compression step, except after the multistage centrifugal pump which causes minimal temperature rise (10 to 15 °F). Additional description of the Surface System is provided in the following paragraphs.

The Process Control Strategy Diagram (PCSD) in Figure 4-2 depicts the key control loops and instrumentation for the compression train. The compression train receives the relatively low pressure CO_2 stream from an existing primary water scrubber overhead stream. The gas enters the inlet separator, TK-101, where any free water carry-over from the scrubber is allowed to drop out. The water level in TK-101 is controlled by a level switch (LSH-101). The pressure (PTX-101A) and temperature (TIT-101A) of the TK-101 overhead stream are measured before the stream enters the blower, BL-101, where the CO_2 pressure is increased by approximately 16 psi. The blower outlet temperature and pressure are monitored by TIT-101B and PTX-101B. The gas stream is then cooled by a shell and tube gas cooler, HE-101. The outlet gas temperature is measured by TIT-102A and controlled at a set point of 95 °F via TCX-102A which is located on the heat exchanger cooling water outlet. The gas pressure downstream of the HE-101 is measured by PTX-102. The outlet cooling water temperature of HE-101 is measured by TIT-005.

The CO_2 stream then enters the blower after cooler separator, TK-102, where any condensed liquid is allowed to drop out. The water inventory in TK-102 will be controlled by a level controller (LC-102). The gas stream is monitored for the presence of oxygen by an online oxygen analyzer ARX-001. A high oxygen reading may indicate an air leak into the system and that will require action from the operations staff. The overhead stream from the blower after cooler separator is split and enters the suction of two parallel 4-stage reciprocating compressors, VC-201 and VC-301. The suction pressure to the reciprocating compressors is controlled by PIC-102 which is located downstream of the TK-102 and upstream of the reciprocating compressors.

Each compression stage has a suction scrubber to remove any liquids, a suction pulsation bottle, compression cylinder(s), a discharge pulsation bottle, and cooler. Compressed CO_2 from the 3rd stage of reciprocating compressors is cooled and then combines and enters the dehydration unit inlet separator where condensed liquids disengage from the vapor stream. The CO_2 stream then enters the bottom of the contactor where it is contacted counter currently with the lean (low water content) glycol that enters at the top of the contactor. The dry CO_2 exiting the top of the contactor is cooled in a gas/glycol exchanger before splitting and returning to the 4th stage compressor suction scrubbers. The Process Control Strategy Diagram (PCSD) in Figure 4-3 depicts the triethylene glycol dehydration system including the inlet separator, the contactor, and the equipment on the regeneration skid that heats the water rich glycol to approximately 400 ^oF in order to boil water out of the glycol so that the regenerated, lean glycol can be returned to the contactor and reused to dry more CO_2.

The pressure of the combined reciprocating compressor discharge is measured by PIT-005 and the flow rate is measured by FIT-005. The pressure is controlled at a set point of up to1400 psig by PIC-005 which allows excess compressed CO_2 to flow back to the process vent header if the injection rate to the wellhead is reduced. The temperature of this vent stream is monitored by TIT-004 and is associated with a low header temperature alarm.

Temperature control loops for each of the inter-stage shell and tube coolers (three for each compressor) as well as the temperature control for the final after cooler will control the outlet CO_2 temperature at a set point of 95 °F via a temperature control output signal to a flow control valve on the cooling water outlet of each exchanger. The CO_2 pressure and temperature after the final cooler outlet is measured using PIT-006 and TIT-006.

CO_2 flow to the wellhead is monitored by flow indicating transmitter FIT-006 and is controlled by flow controller FIC-006 in one of two ways, depending on if the multistage centrifugal pump is or is not used. If the wellhead injection pressure, as indicated by PIT-009 is 1400 psig or less, the pump will not be used and FIC-006 will control flow via flow control valve FCV-341. If the required wellhead injection pressure is greater than 1400 psig, then the pump will be used and FIC-006 will control flow via the variable frequency drive (VFD) on the multistage centrifugal pump. FIT-006 measures the injection rate to the well in both operating modes.

<u>CO_2 Flow Control by Flow Control Valve FCV-341</u>

If the pump is not in use, flow is controlled by flow control valve FCV-341, XV-003 (multistage pump bypass valve) is opened, and valves XV-32 and XV-33 are closed in order to isolate the pump. If the flow rate set point to the wellhead is lowered, FCV-341 throttles to reduce the flow. This restriction in the line will cause the pressure at pressure indicating transmitter PIT-005 to increase. Pressure controller PIC-005 will then open pressure control valve PV-005 to control the pressure at set point by allowing more CO_2 to flow to the process vent header.

<u>CO_2 Flow Control by Pump VFD</u>

If the multistage centrifugal pump PU-404 is required to meet the surface injection pressure necessary to achieve the desired CO_2 injection rate, CO_2 flow will be controlled by changing the pump speed. If the flow rate set point is increased, the variable frequency drive (VFD) on the pump motor will increase the pump speed and thus increase the CO_2 flow rate through the pump and to the injection well. In this scenario, the pump bypass valve XV-003 is closed and valves XV-32 and XV-33 at the multistage centrifugal pump inlet and outlet, respectively, are both open. When the pump is running, FCV-341 and PCV-014 work together as back pressure control valves downstream of the multistage pump to provide back pressure required for some wellhead pressure and flow combinations in the operating envelope of injection flow rates ranging from 250 to 1,100 metric tons / day and surface pressures ranging from 1,400 to 1950 psig.

The water content of dehydrated gas stream is measured between the dehydration unit contactor outlet and the inlet of the fourth stage of the reciprocating compressor via ARX-006. A water content measurement indicating greater than 10 lb/MMSCF (211 ppmv) will result in a process alarm. Operators will be required to investigate and troubleshoot the cause of the alarm.

An automated block valve XV-347 is part of the control scheme for preventing flow of the CO_2 to the well head during emergency shutdowns. Final surface temperature (TIT-009) and pressure (PIT-009) will measured at the well head inlet before the compressed CO_2 enters the well head. A check valve is also provided near the wellhead inlet to prevent backflow from the well into the pipeline.

4.2.4 Filter(s)

Other than the filters on the glycol circulation system, no filters are necessary due to the lack of any significant particulate matter in the CO_2 stream.

4.2.5 Injection Pump

An injection pump (PU-404) is provided to increase the CO_2 stream pressure from 1400 to 1950 psi, if needed in order to inject at the desired rate. This pump is a Wood Group multistage centrifugal pump, model number SJ0270 (TJ9000)/26 and is located in the CO_2 Blower Building.

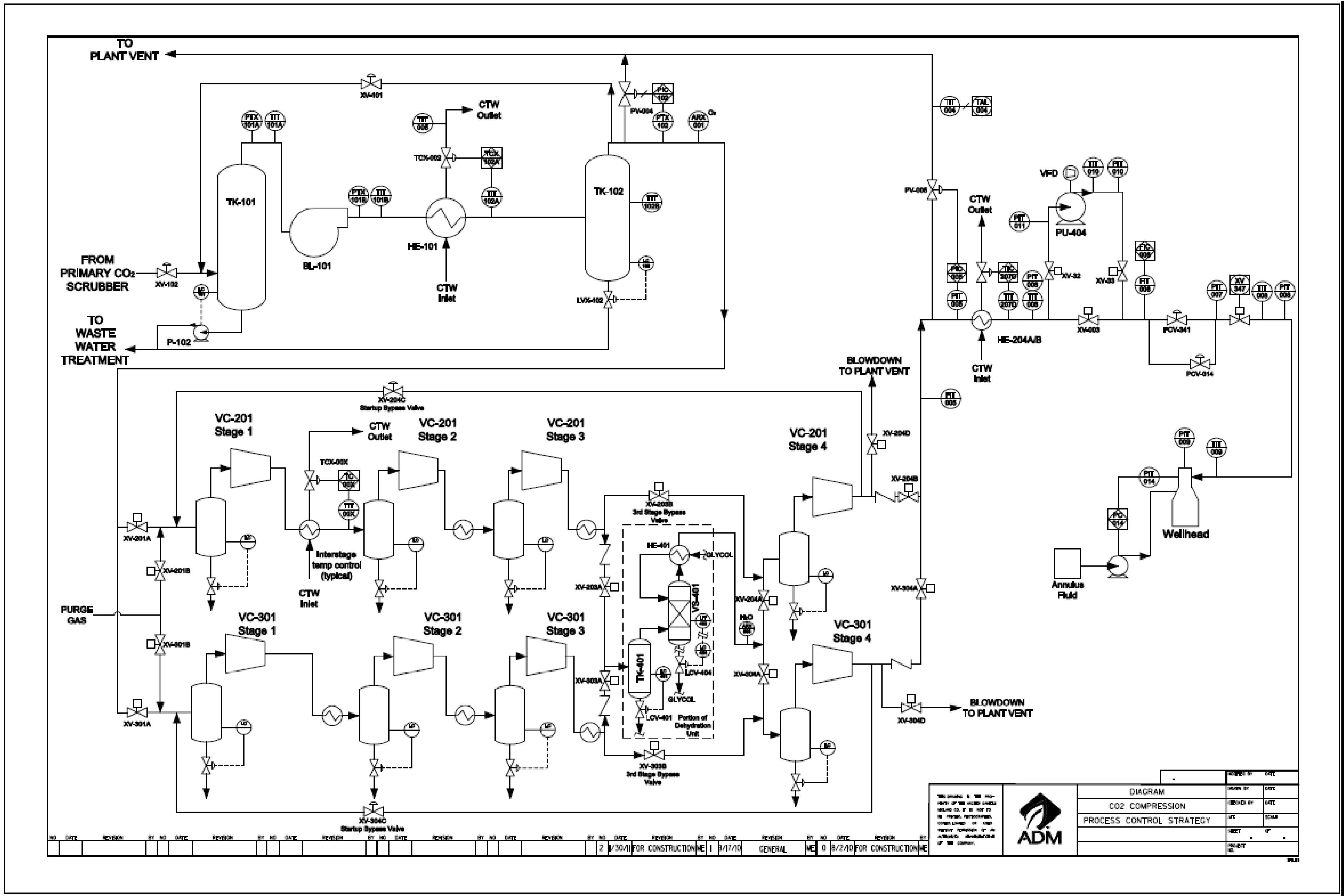


Figure 4 - 2 Process Flow and Control Diagram – Phase III Sequestration Facility Compression Units

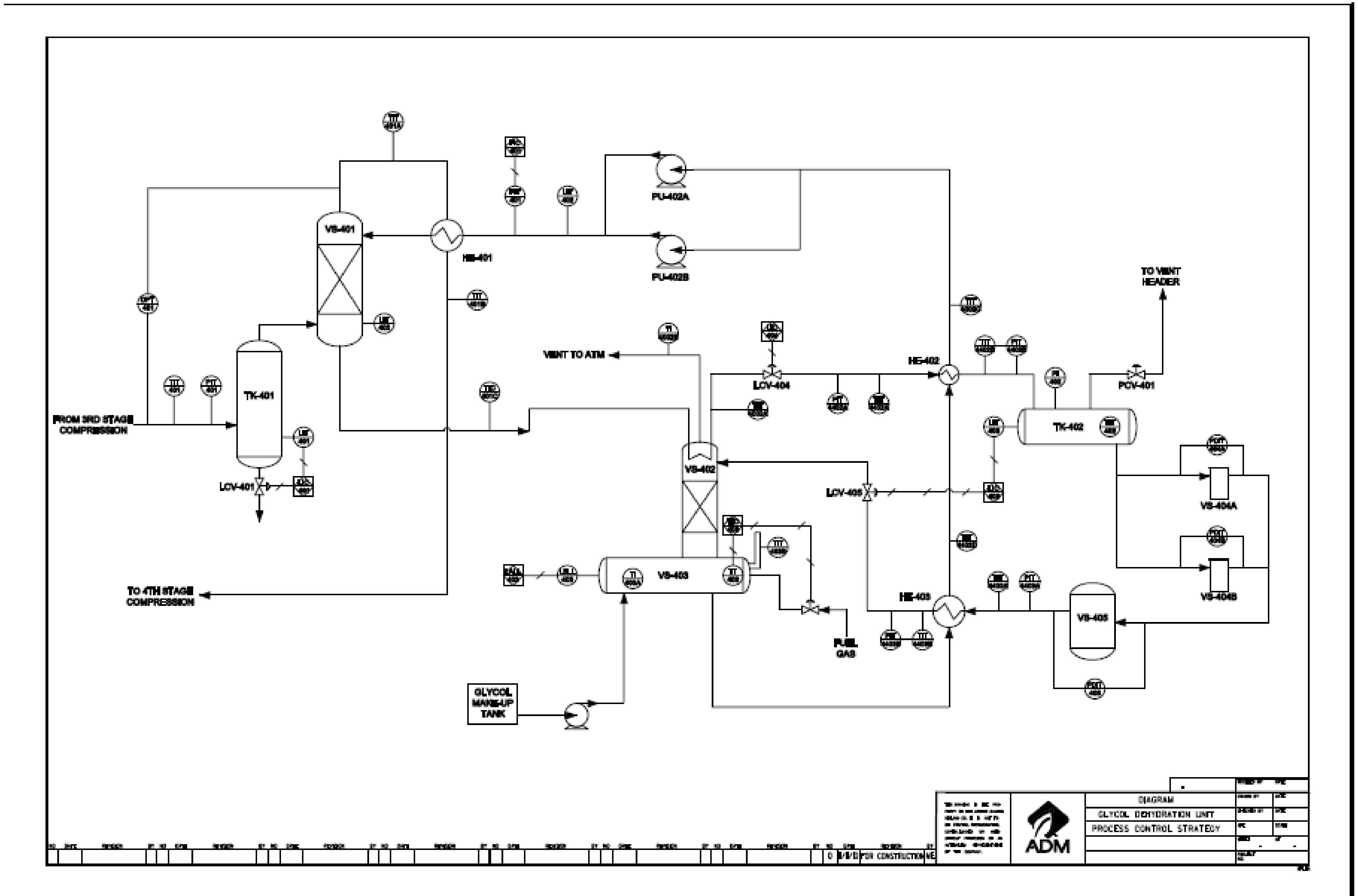


Figure 4 - 3 Process Control Diagram – Phase III Sequestration Facility Triethylene Glycol Dehydration Unit

INJECTED FLUID

5.1. COMPONENT STREAMS FORMING INJECTION FLUID AND GENERATION RATE

The injection-stream is comprised of CO_2 from ADM's biofuel fermentation process. The process produces approximately 3,000 metric tonnes per day (MT/day) of CO_2 at a 1,000,000 gallon ethanol per day production rate.

5.2. VOLUME OF INJECTION FLUID GENERATED DAILY AND ANNUALLY

The target injection rate will initially be 1,000 MT/day for three years; or approximately 1.0 million tons over the duration of the project. The mass of the injected CO2 will be monitored using a mass flow meter that has been installed after compression and dehydration, but prior to well head. The meter and surface instrumentation is described further in Section 4.

5.3. PHYSICAL AND CHEMICAL CHARACTERISTICS OF INJECTION FLUID

The values provided below are based on wellhead pressure and temperature conditions of 2,200 psig and 120°F, respectively. Characteristics of the injection fluid could vary significantly at different locations in the compression and dehydration process and seasonally with changes in ambient temperature. The maximum injection pressure will be 1,950 psi and the actual injection pressure at the wellhead may be lower.

5.3.1 *GENERIC FLUID NAME*

Carbon Dioxide (CO_2)

5.3.2 *FLUID PHASE*

Supercritical and/or dense phase except during startup, shutdown or testing

5.3.3 *COMPLETE INJECTION FLUID ANALYSIS*

Table 5 - 1 Typical Analysis of Feed Stream

(Some Variation is Possible Due to Site-to-Site and Day-to-Day Conditions)

Component	Concentration (mol. %)
CO_2	99+
Total Hydrocarbons	0.01200
N_2	0.01100
H_2S	0.00079
O_2	0.00070

Sample was collected after water scrubber, before CO_2 plant.
Approximate pressure is 14.5 psia

5.3.4 *FLASH POINT* N/A

5.3.5 *ORGANICS*

0.0127 mol. % (based on a typical analysis of the feed stream). Some variation is possible due to site-to-site and day-to-day conditions.

5.3.6 *TDS* N/A

5.3.7 *pH* N/A

5.3.8 *TEMPERATURE*

Approximate temperature is 80°F-120°F (Wellhead temperature may be as low as 60°F).

5.3.9 *DENSITY*

44.3 lbs/cf [at 2,200 psig, 120°F]

5.3.10 *SPECIFIC GRAVITY*

0.71 Specific gravity [at 2,200 psig, 120°F] (liquid water = 1.0)

5.3.11 *COMPRESSIBILITY*

$C_{CO2} = 0.00045\ (psi)^{-1}$ [at 2,200 psig, 120°F]

5.3.12 *MICRO ORGANISMS* N/A

5.3.13 *CHEMICAL PERSISTENCE*

Not applicable. Although CO_2 may be destroyed by natural processes there is a constant supply of CO_2 in the environment because it is naturally occurring, making it different from other anthropogenic chamicals. Furthermore, it does not bioaccumulate with potential long-term toxic effects. EPA definition of persistence: “A chemical's persistence refers to the length of time the chemical can exist in the environment before being destroyed by natural processes.” [Reference: http://www.epa.gov/fedrgstr/EPA-TRI/1999/January/Day-05/tri34835.htm]

5.3.14 *KEY COMPONENT NAME(S)*

Carbon Dioxide (CO_2)

5.4. INJECTION FLUID COMPATIBILITY

At this time there are no compatibility concerns with the injection zone, minerals in the injection zone, and minerals in the confining zone. The CO_2 is expected to have negligible to no reaction with the minerals and formation water. Any reactions that may occur are not expected to affect the containment of the CO_2 below the primary seal. There are compatibility issues with regards to CO_2 if water is present. Components to the injection wellhead and wellbore will be selected to minimize any reaction with the CO_2. All elastomers used will be selected based on contact with CO_2. The compatability of each of the injection and verification well systems and materials is discussed in detail in Section 3.

5.3.15 *PRE-INJECTION FLUID TREATMENT*

Other than dehydration, there will be no pre-injection fluid treatment of the injection fluid (CO_2) at the well site.

5.5. REFERENCES

Bethke, C.M.. 2006. *The Geochemist’s Workbench (Release 6.0) Reference Manual*. RockWare, Inc., Golden CO, 240 p.

Berger, P.M., Mehnert, E., and Roy, W.R. (2009) Geochemical Modeling of Carbon Sequestration in the Mt. Simon Sandstone. Geological Society of America, *Abstracts with Programs*, vol. 41, no. 4, p. 4.

6. AREA OF REVIEW

6.1 INJECTION MODELING

6.1.1 Simulation Software Description and General Assumptions

The IBDP project and the Illinois Industrial Sources (IL ICCS) project injection wells are within 3,500 of each other (Figure 6-3) and the injection periods will overlap. Therefore it was decided that the injection model should account for both projects. Schlumberger Carbon Services utilized ECLIPSE 300 reservoir simulation software with the CO_2STORE module to estimate CO_2 plume migration and reservoir pressure behavior below the site. ECLIPSE 300 is a compositional finite-difference solver. It has been used to simulate hydrocarbon production and other applications including carbon capture and storage modeling. The CO_2STORE module accounts for the thermodynamic interactions between three phases: a water- or brine-phase, a CO_2-phase, and a solid-mineral-phase including NaCl, $CaCl_2$, and $CaCO_3$. Solubilities and physical properties of the brine and CO_2 phases are calculated to match experimental results across a range of typical storage reservoir conditions, including temperatures ranging from 12-100°C and pressures up to 60 MPa. Details of the method used by ECLIPSE are based on Spycher and Pruess (2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components exist in both the liquid and solid phases.
- The CO_2 phase density is obtained by an accurately tuned and modified Redlich-Kwong equation of state (Redlich & Kwong, 1949).
- The brine density is first approximated by the pure water density and then corrected for mineral and CO_2 solubilities and effects by Ezrokhi's method (Zaytsev & Aseyev, 1992).
- The CO_2 gas viscosity is calculated using the method described of Vesovic et al. (1990) and Fenghour et al. (1999).

Simulation-based estimates of fluid conditions throughout the surface pipeline and wellbore indicated that the temperature of the CO2-stream (80-120°f) is close to the formation temperature in the injection interval (119.8-125.7°f). This allowed the simulations to be carried out under isothermal conditions. Although there could be some temperature difference between the injection formation and the pipeline temperature the CO2 should will warm as it goes down the hole and thermal difference are expected to be negligible. ECLIPSE uses time step algorithm to optimize the time step duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, time step size ranged from 8.64×10^1 to 8.64×10^5 seconds or 0.001 to 10 days.

6.1.2 ***Site Specific Assumptions and Methodology***

The 3-D geologic model developed for the project and used as a basis for injection simulations was based on the interpretation of data describe in Section 2. Structurally, the model is based on the interpretation of both 2D and 3D seismic survey data in conjunction with dipmeter log data acquired after drilling CCS #1 and the verification well. Petrophysical and transport properties from the characterization (Section 2) were then distributed throughout each layer in the geocellular model in a homogeneous fashion. The model dimensions are 48.3 km by 48.3 km (30 mi. by 30 mi.). This model is sufficiently large to minimize boundary effects. This assumption was tested using both constant-pressure and no-flow boundary conditions in early runs of the model. Little difference was observed between the runs and subsequent simulations were carried out with no-flow boundary conditions. The grid pattern for the model was refined surrounding the injection wells to provide enhanced detail and accuracy in the areas of the model where the CO2-plum and pressure front see the largest gradients. The grid cells in the vicinity of the injection wells are 15.25 m by 15.25 m (50 ft by 50 ft) in the horizontal plane, while grid cells near the edges of the model domain are 3.2 km by 3.2 km (2 mi. by 2 mi.) in the horizontal plane. **Figure 6-3** illustrates the overall grid dimensions and geometry of the irregular gridding pattern used throughout the model.

The well-log and seismic data (Section 2) indicate that there is a flow-limiting barrier that is laterally continuous within the middle Mt. Simon Sandstone. The barrier was selected as the top of the injection simulation. The model encompasses approximately the lower half of the Mt. Simon Sandstone: from the top of the basal arkosic zone up to a low-porosity, low-permeability flow-limiting barrier. The Eau Claire formation was not included in the injection model because it was not expected that the CO_2 would reach above the flow-limiting barrier and the results (below) indicate that this is the case. **Figure 6-4** shows the porosity and permeability values in the lower half of the Mt. Simon Sandstone including the flow-limiting zone selected for the top of the model. The values are based on porosity values from the CCS #1 well logs and the permeability wastransformed from porosity. Both the porosity and permeability were averaged over the thickness of each model layer. The layering in the model is based upon trends in the petrophysical and facies characteristics observed in both well logs and core samples. The lower half of the Mt. Simon Sandstone was subdivided into 74 layers, which range from approximately 1.2 m (4 ft) to 10 m (33 ft) in thickness. Porosity and permeability within these layers range from 8 to 26% and from 0.03 to 117 millidarcies (mD), respectively. The model's temperature and pressure gradients of approximately 1.8°C/100-m (1°F/100-ft) and 10.2 MPa/km (0.45 psi/ft) were based on in-situ measurements made after drilling and testing CCS #1. The formation pressure gradient in the lower half of the Mt. Simon is higher than a typical fresh-water gradient due to the high salinity observed in this part of the reservoir, which ranges from 179,800 ppm to 228,000 ppm total dissolved solids (TDS) based on analysis of actual formation fluid samples recovered during the drilling of CCS #1 (Frommelt, 2010).

Using the porosity and permeability values observed in log data and core samples obtained from CCS #1, a suite of proprietary relative permeability and capillary pressure curves was developed in collaboration with the CO_2 Sequestration Team at the Schlumberger-Doll Research

Center in Cambridge, MA, USA (Figure 6-5). The relative permeability curves govern the multi-phase flow behavior of the CO_2-brine system during both drainage and imbibition. Figures 6-6 and 6-7 depict the capillary pressure behavior of the CO_2-brine system during drainage and imbibition, respectively, for four different classifications of lithology defined by intrinsic permeability. For example, Pc(1) represents the capillary pressure behavior for lithologies with intrinsic permeabilities less than 1 mD; Pc(2) for permeabilities between 1 mD and 10 mD; Pc(3) for permeabilities between 10 mD and 100 mD; and Pc(4) for permeabilities greater than 100 mD.

Another governing parameter used in the reservoir simulation was the fracture pressure gradient of the lower Mt. Simon Sandstone. The fracture pressure gradient in the lower Mt. Simon was demonstrated via step rate test in CCS #1 to be 16.2 MPa/km (0.715 psi/ft) (Section 2). For the purposes of the reservoir simulations, the bottomhole injection pressure in CCS #1 was allowed to operate up to 80% of this gradient, whereas the bottomhole injection pressure in CCS #2 was allowed to operate up to 90% on account of the higher injection rate.

The simulation was conducted using 6 years of injection and 50 years of post injection. The injection scenario started with CO_2 injection for 1 year at 1,000 MT/day into CCS#1. This was followed by 2 years of dual injection – 1,000 MT/day into CCS #1 and 2,000 MT/day into CCS #2. After the dual-injection period there were 3 years of injection into CCS #2 at 3,000 MT/day with CCS #1 shut-in. The 50-year post injection period was simulated in order to understand the long-term behavior of the CO_2 plume and the reservoir pressure within site. In the case of CCS #1, the existing net perforated interval of 16.8 m (55 ft) was assumed for the simulations (Frommelt, 2010), whereas in the case of CCS #2, a perforated interval of 100 m (330 ft) was required to meet the maximum proposed injection rates.

6.2 PRESSURE FRONT DETERMINATION

The AoR is based on the *Maximum Extent of the Separate-phase Plume or Pressure-front (MESPOP)* methodology, as detailed in the Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators (USEPA, 2011). Information about the lowermost USDW and target injection zone was obtained from the characterization of the site (Section 2) and provided the input for the hydraulic head calculations specified in the guidance (Locke & Mehnert, 2011). **Figure 6-1** provides the input values for the calculation of the pressure front. It also describes the graphical relationship between the hydraulic head in the lowermost USDW and that of the target injection interval of the lower Mt. Simon Sandstone. Results of these calculations indicate that the pressure front in the injection zone ($P_{i,f}$) is delineated by a pressure of 22.77 MPa (3302 psi), or a change in pressure of 1.27 MPa (184 psi) above the initial reservoir pressure. Based on computer modeling of the proposed injection- and post-injection period, the MESPOP grows to a maximum extent of approximately 3.2 kilometers (2.0 miles) and is exclusively defined by the pressure front and not by the extent of the CO_2 plume. As a result, the CO_2 plume remains within the AoR throughout the entire simulated period. **Figure 6-2** outlines the predicted extent of the pressure front within the injection interval over a topographic map of the immediate area around the project site. It should be noted that the jagged shape of the polygon outlined in blue is an artifact of the coarseness of the simulation grid. To be conservative the boundary of the AoR was extended to the green line inscribing the blue polygon, which extends and smoothes the AoR boundary.

6.3 SIMULATION RESULTS

The injection interval is near the base of the Mt. Simon and the CO_2 flows upward from the injection interval due buoyancy. As it rises, CO_2 saturation increases below the lower permeability intervals within the Mt. Simon. These intervals are expected to be laterally continuous based on the interpretation of the site-seismic data (Section 2). The increase in saturation causes the CO_2 plume to gradually pool and spread laterally beneath these lower permeability strata which results in slow growth of the plume footprint to an area of approximately 3.9 km^2 at the end of the 50-year post-injection period. It is these lower permeability strata within the Mt. Simon that also limit the ultimate vertical migration through the injection zone, such that after five years of continuous injection through the IL-ICCS well and 50 years of shut-in, the CO_2 remains well within the lower half of the Mt. Simon. The development of and interaction between the CO_2 plumes resulting from injection into CCS #1 and CCS #2 is can be seen in **Figure 6-8**. **Figure 6-9** through **Figure 6-21** depict map-view representations of the aggregate plume area at various times superimposed on a satellite image of the project area. Each figure is accompanied by an estimate of the aggregate area (in square kilometers) of the two plumes. Also depicted in **Figure 6-9** through **Figure 6-21** is the development of the pressure front ($P_{i,f}$) boundary through simulated time. Each figure is accompanied by an estimate of the area encompassed by the pressure front (in square kilometers). **Figure 6-22** and **Figure 6-23** summarize this same information in graphical form for both the pressure front and CO_2 plume throughout the simulated time period.

It is noteworthy that the pressure front boundary continues to grow throughout the injection period (through Year 6) to a maximum area of 32 km^2, after which point the reservoir pressure quickly decays due to lack of injection. By Year 8, the pressure throughout the reservoir has dropped below the threshold pressure defined above (i.e., $P_{i,f}$ = 22.77 MPa). One implication of this prediction is that after Year 7, the AoR could be delineated exclusively by the footprint of the aggregate CO_2 plume rather than by pressure, which dramatically reduces the size of the AoR during the post-injection period.

Several additional interesting features can be identified in the sequence of images presented in **Figure 6-8** through **Figure 6-21**. First, the shape of the CO_2 plume created by injection through CCS #1 is initially symmetrical during the first year of simulated injection due to the homogeneous nature of the geologic model. The symmetry of the plume is altered, however, once injection begins in CCS #2 and this effect becomes more dramatic throughout simulated time. This highlights the fact that, as a result of the pressure interference, the concurrent injections will influence each other even before the CO_2 plumes interact.

Another observation is that the brine displaced ahead of the advancing CO_2 plume created by the injection into CCS #2 not only distorts the shape of the plume around CCS #1, but also sweeps away mobile CO_2 from the nearest edges of the plume, leaving behind a 'shadow' of residually-trapped CO_2. This affect is most apparent when comparing the Year 3 and Year 7 cross-sectional views in **Figure 6-8**. The CO_2 that is residually trapped as a result of the encroaching brine is depicted in light-blue, or the 0.2 – 0.25 range in the CO_2 saturation color bar. This residually-trapped CO_2 is immobilized by capillary forces and can be seen to persist through the remaining cross-sectional images in **Figure 6-8**, suggesting long-term storage in the lower Mt. Simon.

A third notable observation is the difference in the size of the plumes. While dramatic, this size difference is easily explained by the difference in injection rates of CO_2 into the two wells: 1000 MT/day for three years into CCS #1 versus 2000 MT/day for two years and 3000 MT/day for three years into CCS #2. Furthermore, the perforated interval simulated in the two wells is dramatically different: 16.8 m in CCS #1 versus 100 m in CCS #2. This difference alone accounts for the majority of the difference in plume height observed in **Figure 6-8**.

Finally, a fourth notable observation is the continued vertical growth of the plumes throughout the simulated 50-year post-injection period. Although the CO_2 plumes do continue to grow vertically under buoyant forces after injection ceases, the vertical extent is ultimately limited by lower permeability intervals within the Mt. Simon. The cross-sectional profiles at various times depicted in **Figure 6-8** illustrate how the CO_2 saturation increases below these lower permeability strata, which results in the lateral spreading of the CO_2 plume. While this does increase the footprint area of the plume, it retains the CO_2 well within the lower half of the Mt. Simon. Moreover, as can be seen in the Year 56 profile of **Figure 6-8**, the plume has not even reached the upper model boundary, which in this case, only extends to the low-porosity, low-permeability interval mid-way through the Mt. Simon Sandstone.

<u>Geochemical Modeling</u>. No compatibility problems are anticipated in the injection zone. Geochemical modeling was used to predict the effects of injecting supercritical CO_2 into a model Mt. Simon Sandstone (Berger, Mehnert, & Roy, 2009). Based on chemical and mineralogical data from the Manlove Gas Storage Field in Illinois, the geochemical modeling software package, Geochemist's Workbench (Bethke, 2006), was used to simulate geochemical reactions. As expected, the injected CO_2 decreased the pH of the formation brine to about pH 4.5. As the reaction was allowed to progress, the pH of the formation brine increased to pH 5.4.

In the geochemical simulations mentioned above, Berger et al (2009), predicted that illite and glauconite dissolved initially. As the reaction was allowed to proceed, kaolinite and smectite were predicted to precipitate. It was predicted that the volume of pore space would not be significantly altered (Berger, Mehnert, & Roy, 2009). Therefore, no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates, are expected.

Geochemist's Workbench predicts the geochemical reaction of CO_2 with the Eau Claire Formation. Modeling results indicated that illite and smectite would initially dissolve, but that the dissolved CO_2 could be precipitated as carbonates (Berger, Mehnert, & Roy, 2009). This dissolution and precipitation process is not expected to affect the caprock integrity.

6.4 WELLS WITHIN THE AREA OF REVIEW

6.4.1 *Tabulation of Well Data Within the AoR*

Well logs for all wells within the AoR were obtained from four databases. Records for water wells were obtained from the Illinois State Geological Survey (ISGS) ILWATER database and the Illinois State Water Survey (ISWS) water well database. Records for oil and gas wells were obtained from the ISGS ILOIL database. In addition, logs for coal stratigraphic tests were obtained from the ISGS Coal Section. The ISWS and ISGS are the repository for all well logs acquired since 1965; however, well logs filed prior to that year were done so on a voluntary basis.

A total of 432 wells are known to be drilled within the AoR (**Figure 6-2**). The deepest well (excluding the IBDP injection, verification, and geophysical wells) is 762 m (2,500 ft). Fourteen wells within the AoR have been drilled to the depth range of 640 to 762 m (2,100 to 2,500 ft).

The wells listed in the ISGS and ISWS databases were cross-checked to remove duplicates. The duplicates were identified by well owner, location, and/or well depth. Several wells identified only by a general location description (section, township, and range) were assumed to be within the AoR, although it is possible these wells may actually be located beyond the AoR limits.

Water wells (371 of 432 wells) are the most common well type. The domestic water wells have depths of less than 60 m (200 ft). Other wells include stratigraphic test holes, other water wells, and oil and gas wells. Appendix I provides a full size map of the wells within the AoR and a listing of these wells with their API number, well owner, well location, well type, and well depth identified.

Ten oil and gas wells are located within approximately 2.4 km (1.5 miles) from the proposed injection well location. The closest well is located in the northeast quarter of Section 5, T16N, R3E. This well (API number 121150061800) was drilled as a gas well in 1933 and was 27 m (88 ft) deep. There is no record of this well being plugged. This well was likely collecting naturally occurring methane from the Quaternary sediments. The other 9 wells are located in Section 5, T16N, R3E or Section 28 and Section 29, T17N, R3E. The deepest of these oil wells is API number 121150054700, located in the northwest quarter of Section 28. This well was drilled into the Lower Devonian and was 714 m (2,344 ft) deep. None of these wells are deep enough to interact with the plume, pressure front, Eau Clair formation, or Mt Simon formation.

6.4.2 *Number of Wells within the AoR Penetrating the Uppermost Injection Zone*

With the exception of the CCS#1 injection and verification wells, there are no known wells within the area of review that penetrate deeper than 762 m (2,500 ft). The depth to the top of the injection zone (Mt. Simon Sandstone) is 1690 m (5,545 ft). These are only two known wells that penetrate the uppermost injection zone. This implies that no other wells have been drilled, plugged and abandoned, temporarily abandoned, or are operating within the AoR

6.4.3 *Proposed Corrective Action for Unplugged Wells Penetrating the Injection Zone*

No wells have been found that are believed to require corrective action. The AoR will be re-evaluated periodically (see Section 6.6 below) to verify whether corrective actions may be necessary in the future.

6.5 AREA OF REVIEW RE-EVALUATION & CORRECTIVE ACTION PLAN

6.5.1 AOR RE-EVALUATION.

The AoR will be re-evaluated on minimum of a 5-year basis following issuance of the Class VI UIC permit. The plan will use newly collected and existing data to update and verify the site model and re-evaluate the size and shape of the AoR. Figure 6-24 provides a flowchart for the Re-evaluation process. Table 6-1 Summarizes the key types of monitoring and operational data that may be used for re-evaluation. During each re-evaluation, the following will be performed:

- New wells within the AoR that exceed a depth of 305 m (1,000 ft) will be identified and evaluated for corrective action based on available information;
- Wells exceeding a depth of 305 m (1,000 ft) within the AoR that have been plugged & abandoned since the last AoR re-evaluation will be identified based on available information;
- Monitoring and operational data from the injection well, verification well, other surrounding wells, and other sources will be used to re-evaluate whether the predicted CO_2 plume and pressure front predictions are consistent with the observations. .

Monitoring and operational data will be analyzed on a frequent (likely annual) basis by ADM and/or its partners. If new data are inconsistent with existing model predictions, the reasons for the inconsistency will be identified and analyzed. If data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume is occurring, or if the actual reservoir pressures are significantly different than predicted pressures, ADM will initiate an AoR re-evaluation, prior to the 5-year re-evaluation period.

6.5.2 RE-EVALUATION REPORT

Following each AoR re-evaluation, a report will be prepared documenting the re-evaluation process. The report will include the updated modeling, the data used for the re-evaluation, any corrective actions needed, and the schedule for any corrective actions to be performed. The report will be submitted to the U.S EPA within a timeframe specified by permit.

If no changes result from the AoR re-evaluation, the report will include the data and results demonstrating that no changes are necessary.

6.5.3 CORRECTIVE ACTION

Based on the available information obtained for the AoR project at the time of this application, no corrective actions are believed to be necessary because no wells other than the injection well (CCS #1) and the verification well penetrate the confining zone.

If corrective actions are warranted during the injection or post-injection period based on AoR re-evaluation, ADM will take the following actions:

- Identify all wells or features within the AoR that may require corrective action
- Identify the appropriate corrective action the well or feature requires
- Prioritize corrective actions to be performed
- Conduct corrective actions under a schedule that minimizes risk to USDWs

6.6 REFERENCES

Berger, P. M., Mehnert, E., & Roy, W. R. (2009). Geochemical Modeling of Carbon Sequestration in the Mt. Simon Sandstone. *Abstracts with Programs , 41* (4), 4.

Bethke, C. M. (2006). *The Geochemist's Workbench (Release 6.0) Reference Manual.* Golden, CO: Rockware, Inc.

Fenghour, A., Wakeham, W. A., & Vesovic, V. (1999). The Viscosity of Carbon Dioxide. *J. Phys. Chem. Ref. Data , 27* (1).

Frommelt, D. (2010). *Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, – UIC Permit UIC-012-ADM.* Archer Daniels Midland Company.

Locke, R. A., & Mehnert, E. (2011). *Quarterly Groundwater Report for Illinois EPA Underground Injection Control Permit Number UIC-012-ADM (2011 Q1).* University of Illinois, Illinois State Geological Survey.

Redlich, Otto, & Kwong, J. N. S. (1949). On the Thermodynamics of Solutions. V. An Equation of State. Fugacities of Gaseous Solutions. *Chemical Reviews,* 44 (1): 233.

Spycher, N., & Pruess, K. (2005). CO2-H2O mixtures in the geological sequestration of CO2. II. Partioning in chloride brines at 12-100C and up to 600 bar. *Geochimica et Cosmochimica Acta , 69* (13), 3309-3320.

USEPA. (2011). *Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators.* Office of Water, EPA 816-D-10-007.

Vesovic, V., Wakeham, W. A., Olchowy, G. A., Sengers, J. V., Watson, J. T., & Millat, J. (1990). The Transport Properties of Carbon Dioxide. *J. Phys. Chem. Ref. Data , 19* (3).

Zaytsev, I. D., & Aseyev, G. G. (1992). *Properties of Aqueous Solutions of Electrolytes.* Boca Raton, FL: CRC Press.

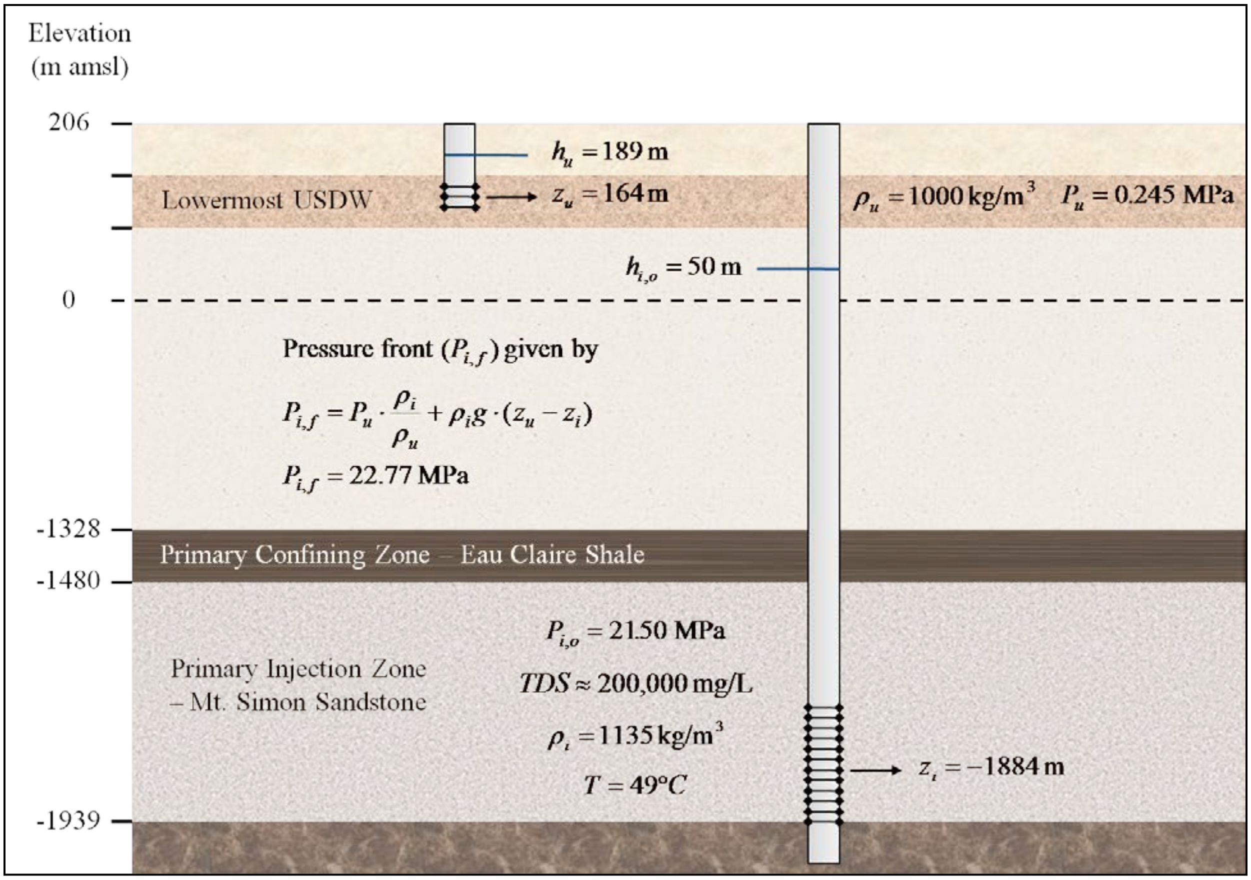


Figure 6 - 1 Illustration of pressure front delineation calculation based on data from IL-ICCS site.

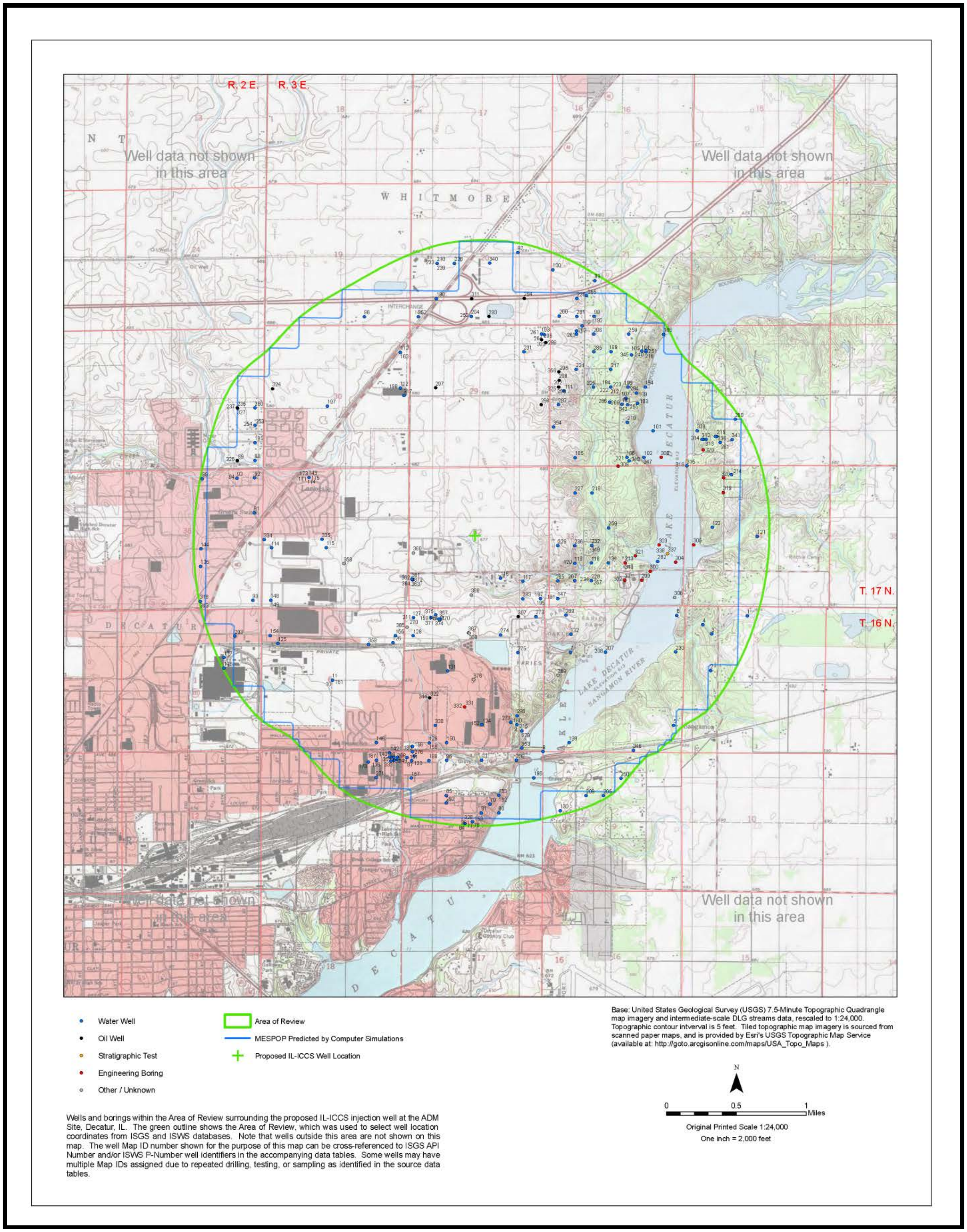


Figure 6 - 2 Well Penetrations within approximately 3.2 km (2.0 mile) radius of site.

Source: ISWS and ISGS databases, data current as of May 10, 2011.

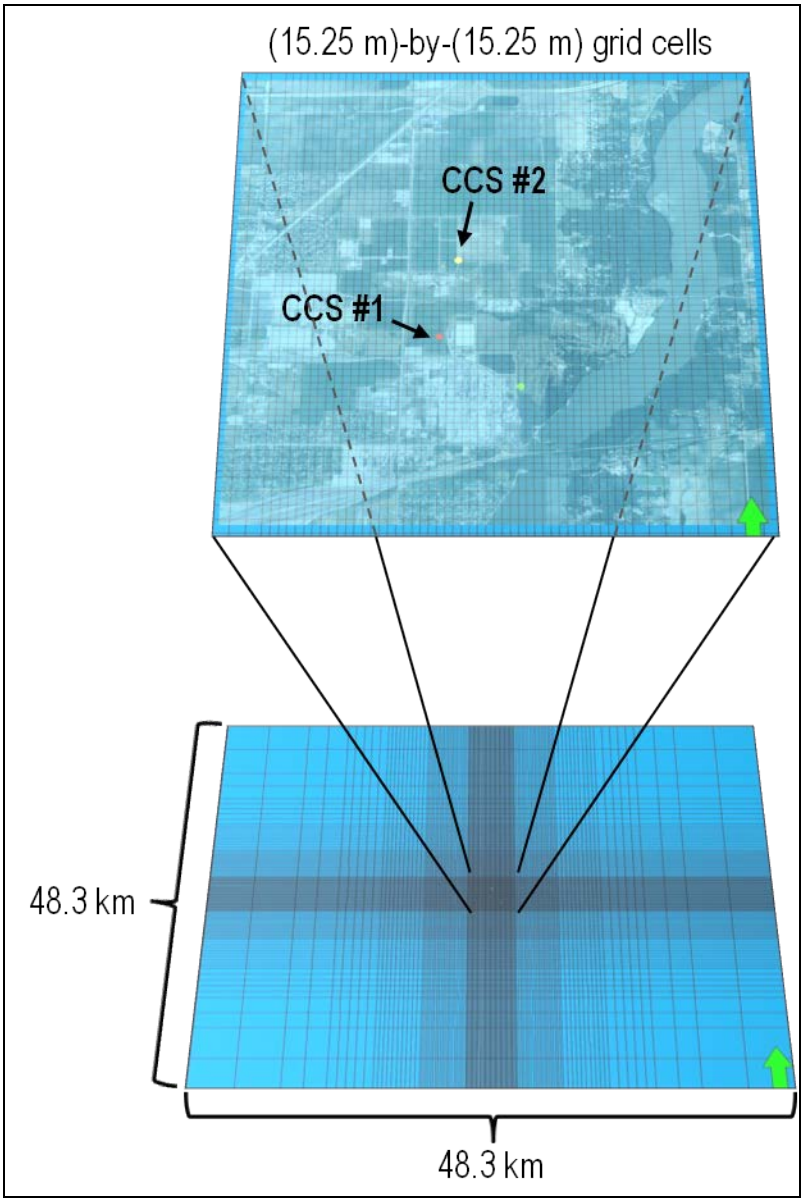


Figure 6 - 3 Depiction of irregular gridding pattern and dimensions of geocellular model used in reservoir simulations.

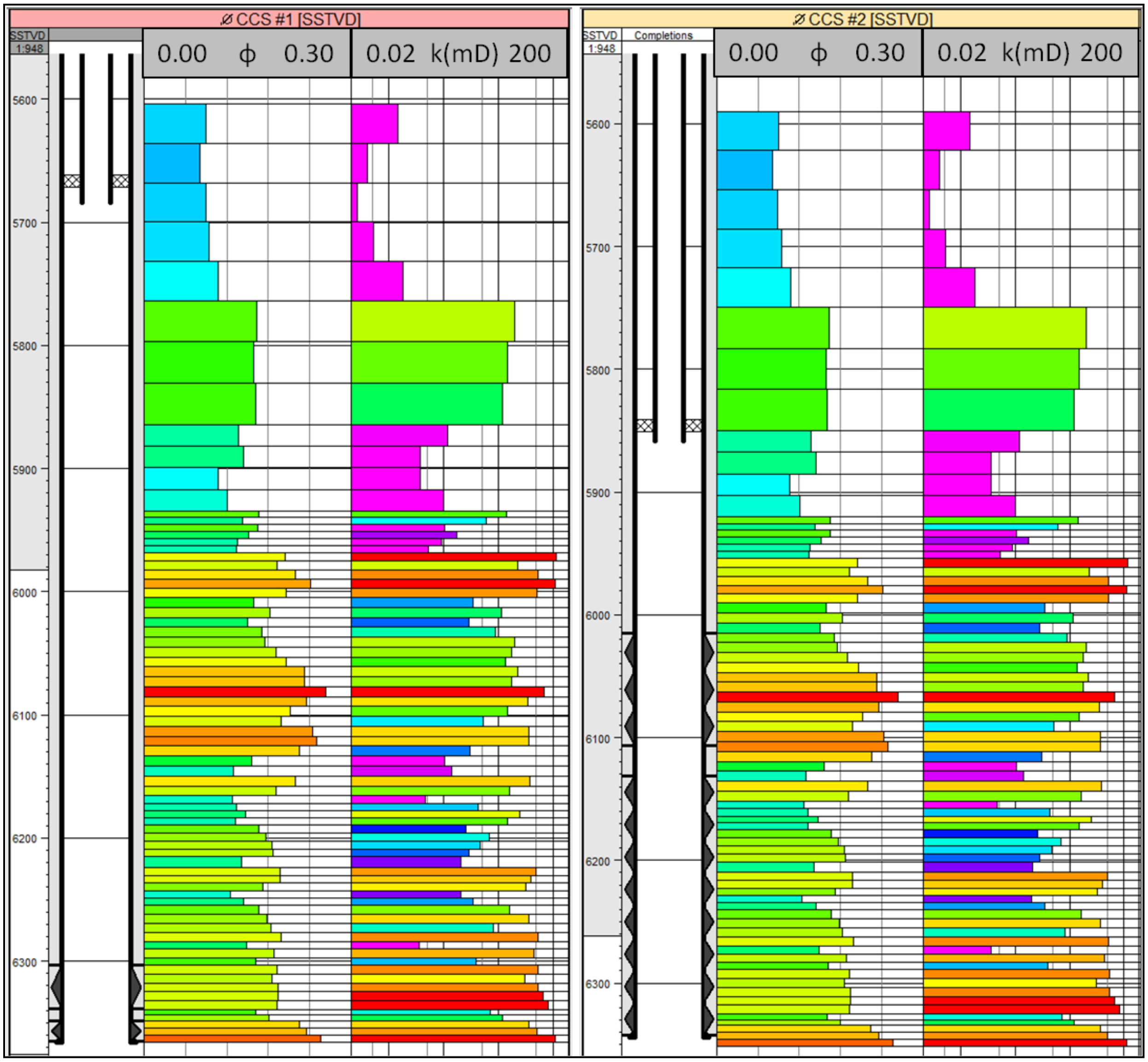


Figure 6 - 4 Upscaled well logs with respect to sub-surface true vertical depth (SSTVD) in feet of porosity and permeability (mD) from CCS #1 and proposed IL-ICCS injection well.

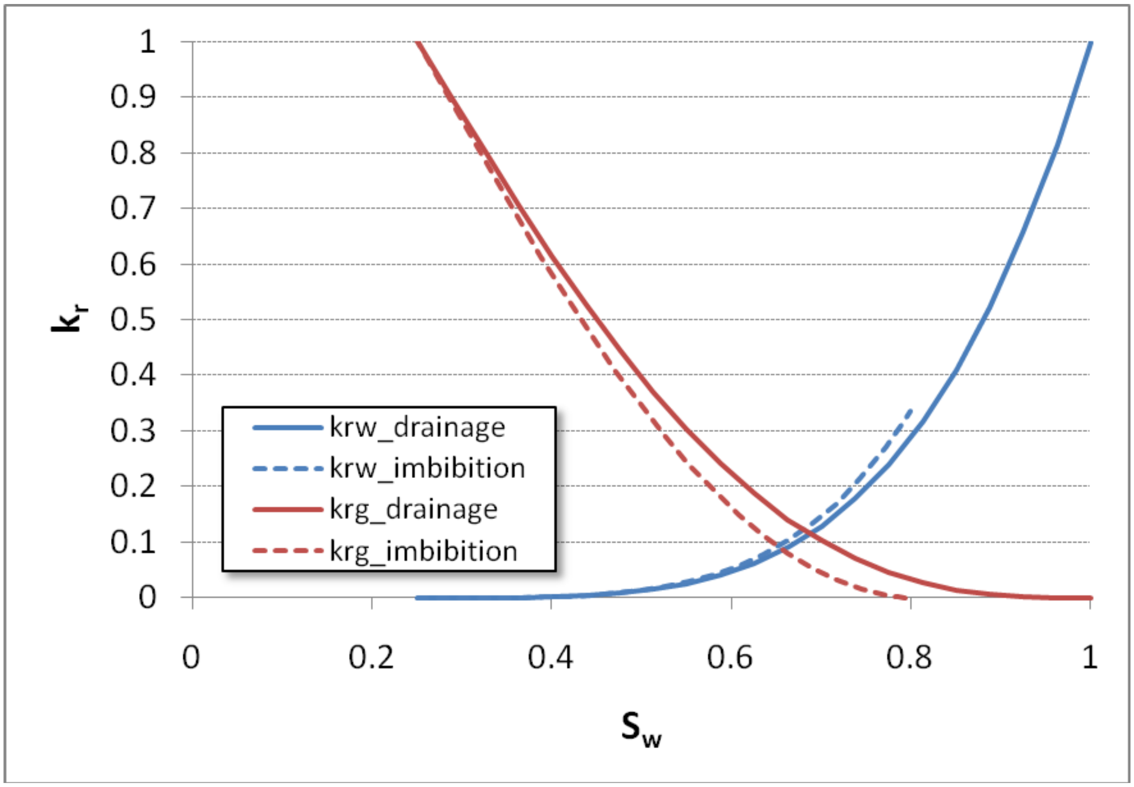


Figure 6 - 5 Relative permeability curves of the CO2-brine system during drainage and imbibition.

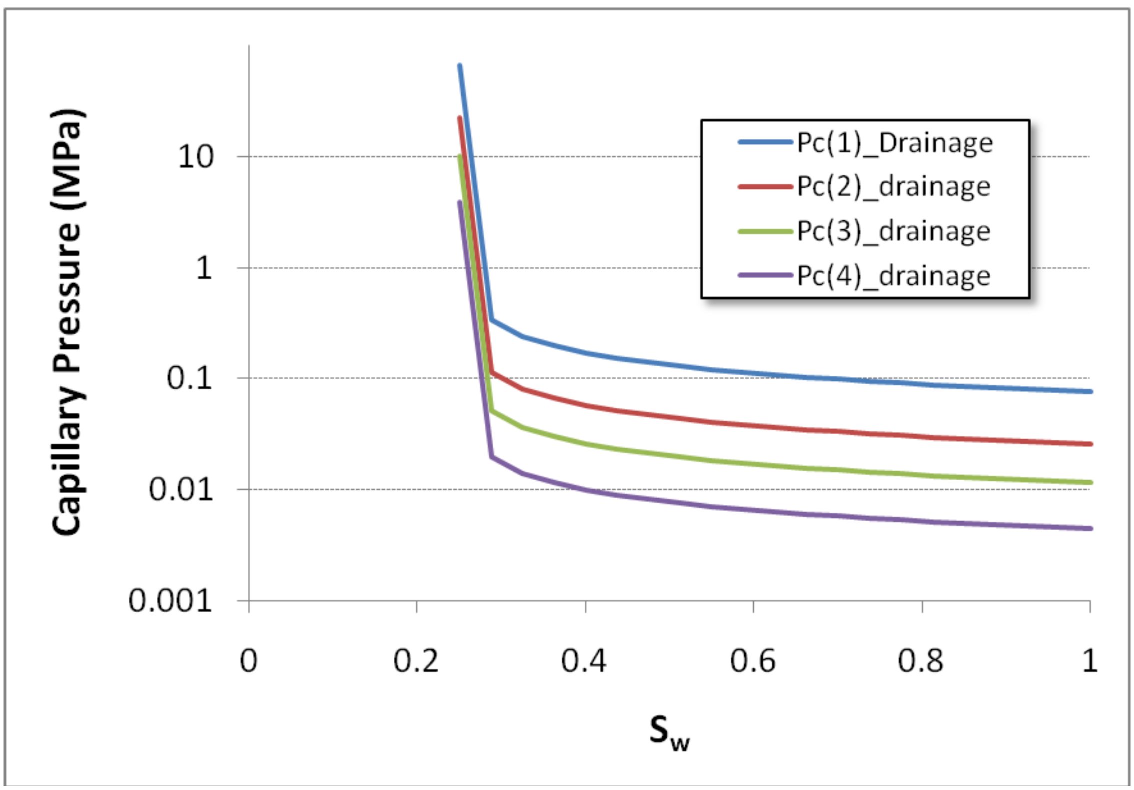


Figure 6 - 6 Capillary pressure behavior of the CO2-brine system during drainage.

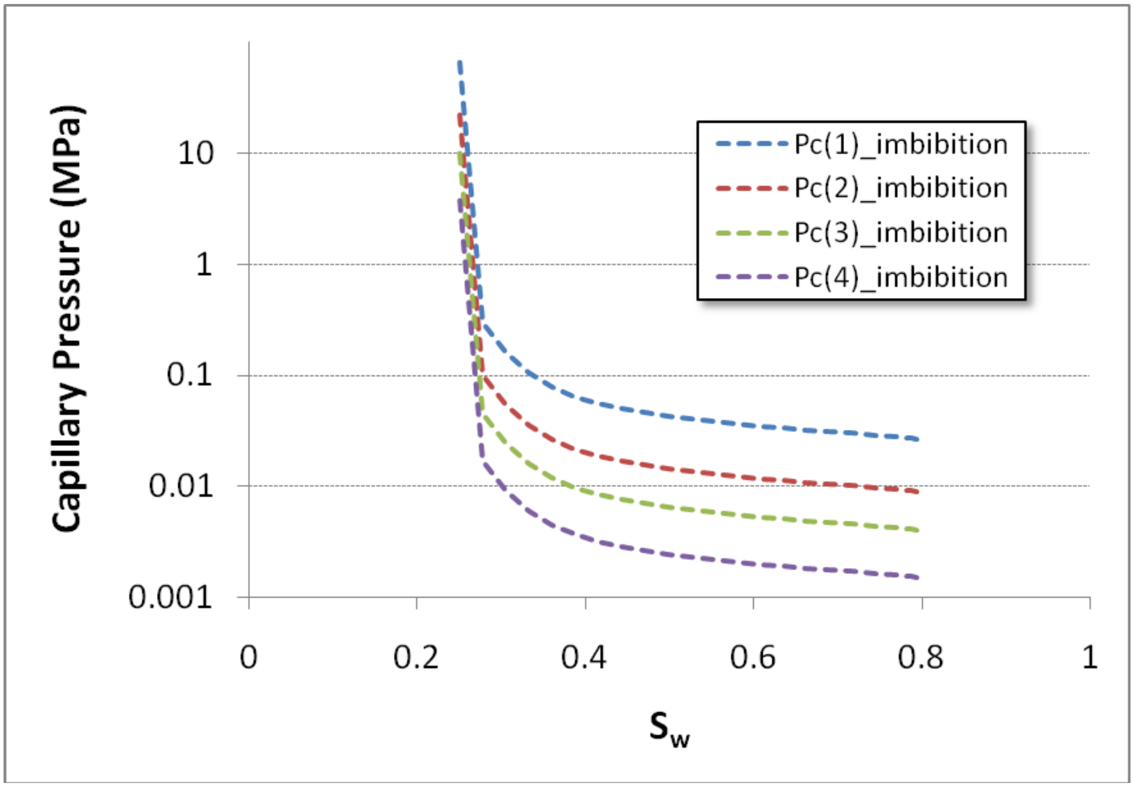


Figure 6 - 7 Capillary pressure behavior of the CO2-brine system during imbibition.

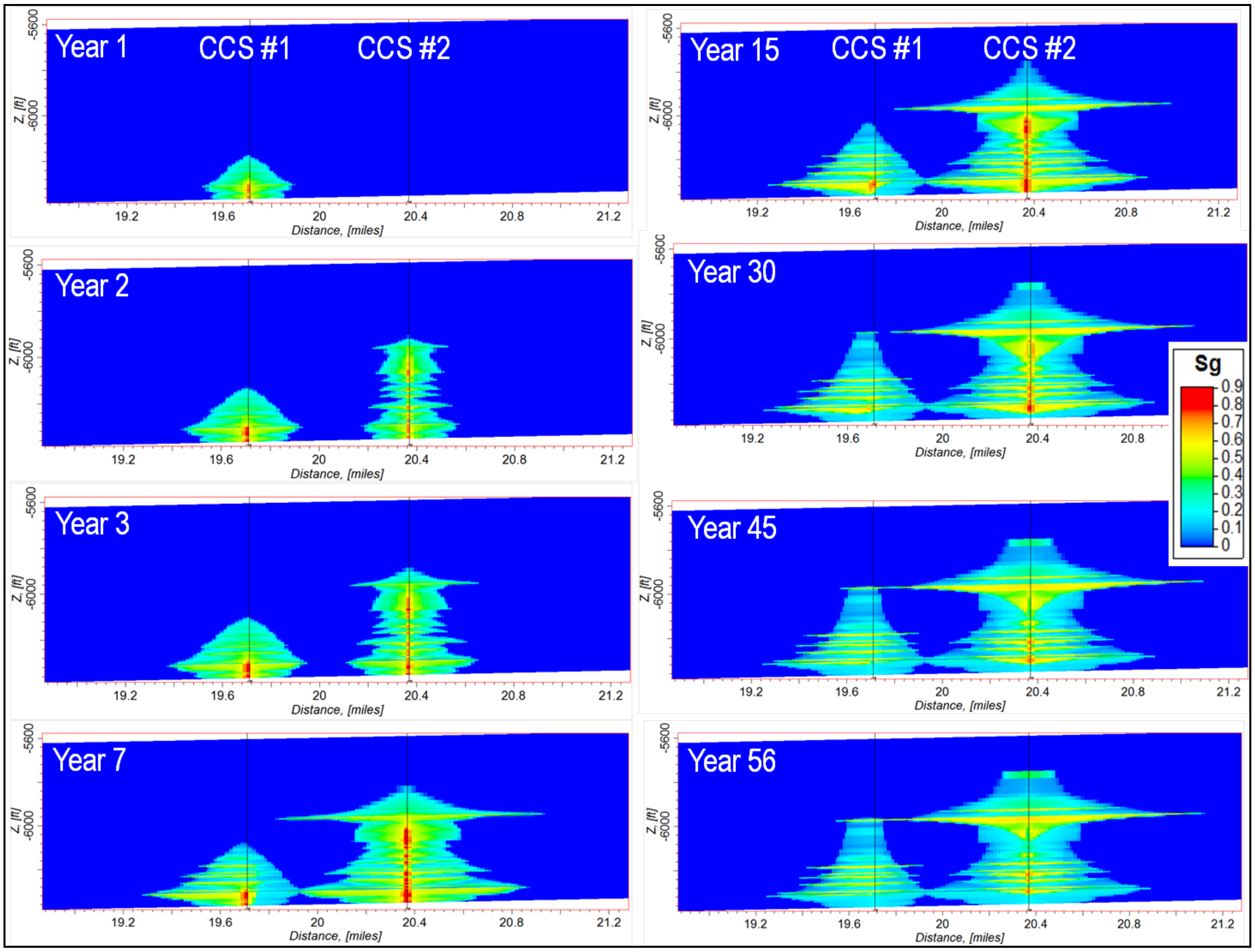


Figure 6 - 8 Cross-sectional views of CO2 plumes (represented by gas saturation, Sg, ranging from 0 to 1) at various time steps during simulation.

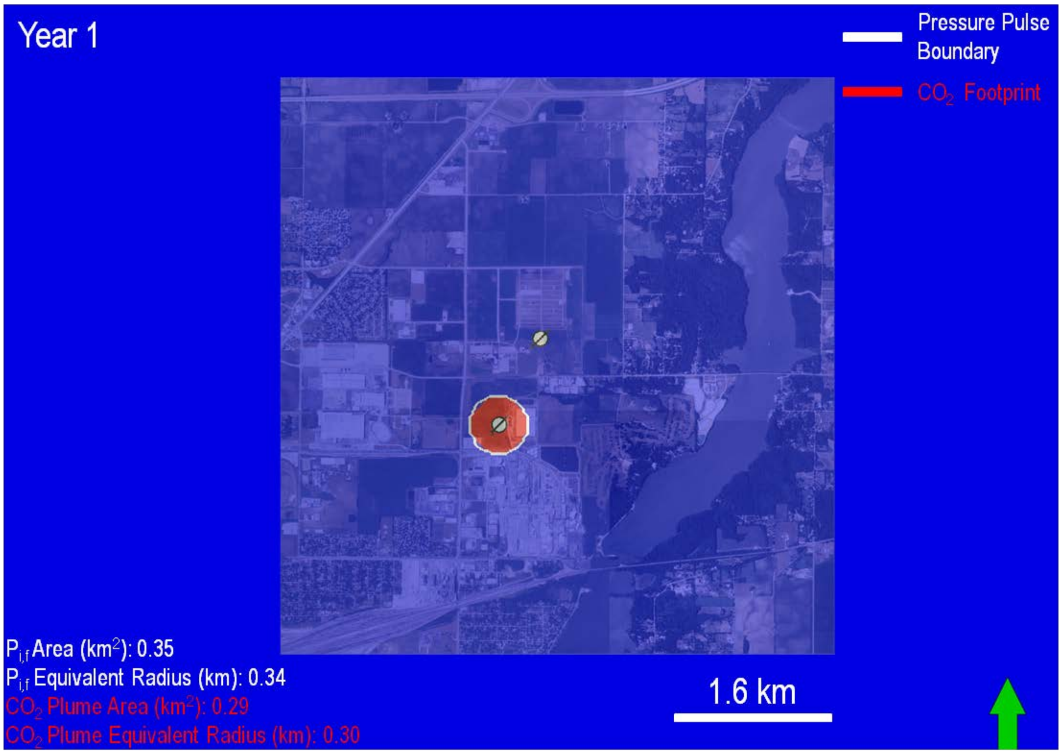


Figure 6 - 9 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 1.

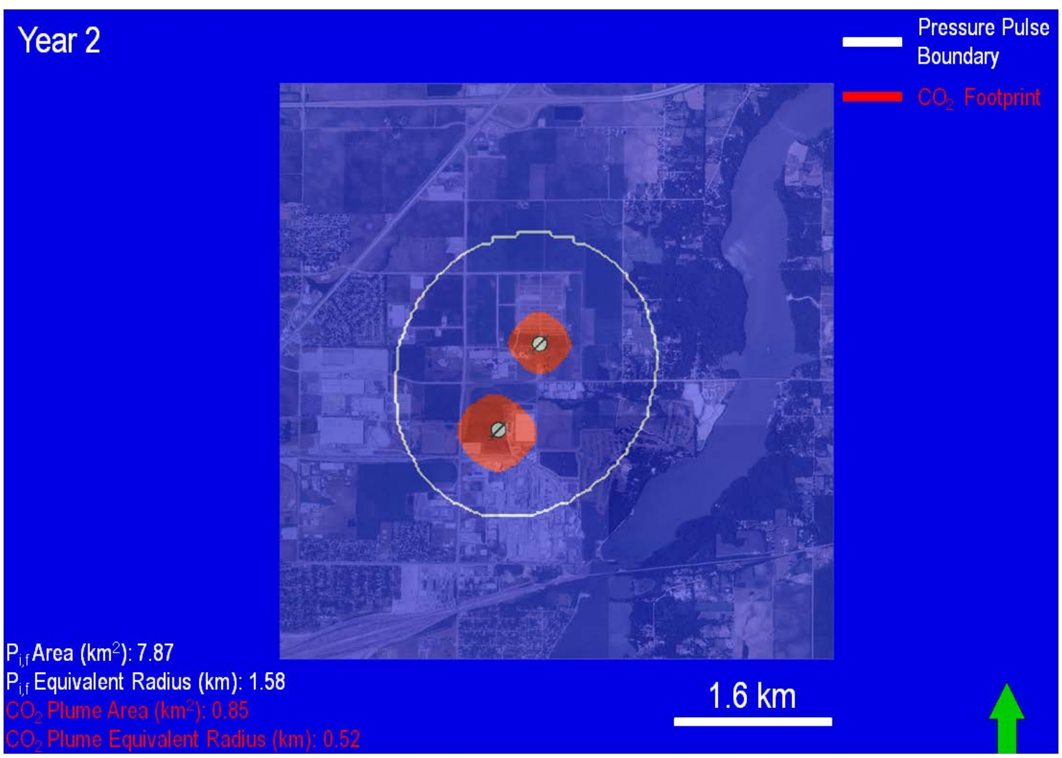


Figure 6 - 10 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 2.

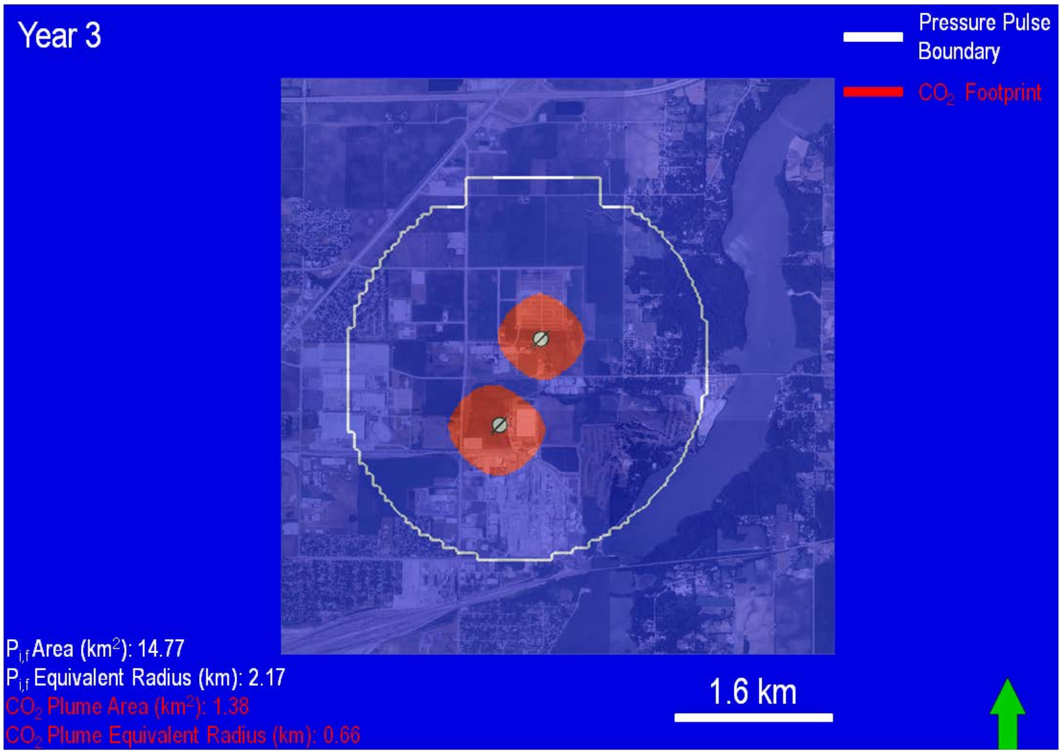


Figure 6 - 11 -view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 3.

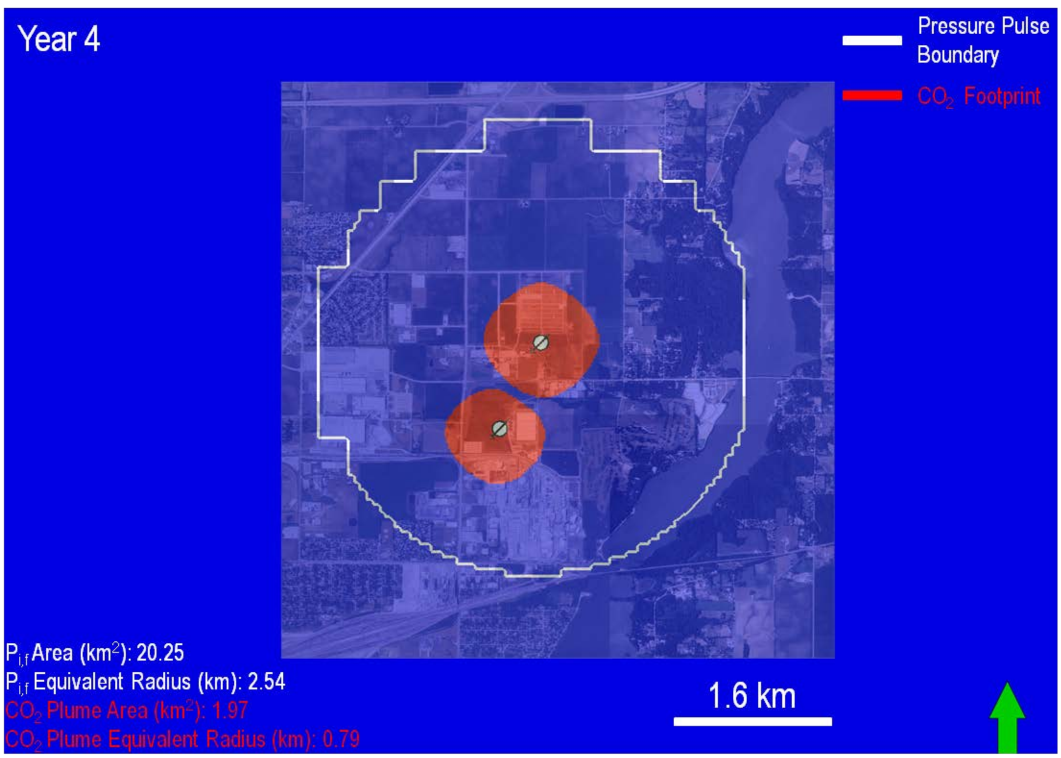


Figure 6 - 12 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 4.

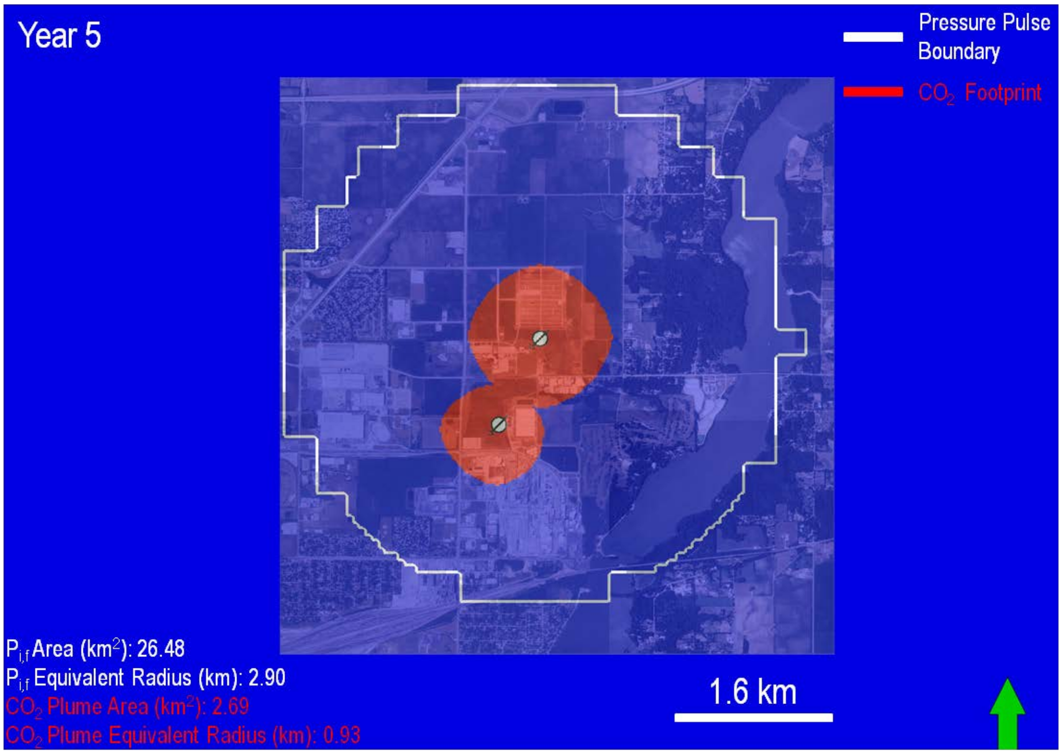


Figure 6 - 13 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 5.

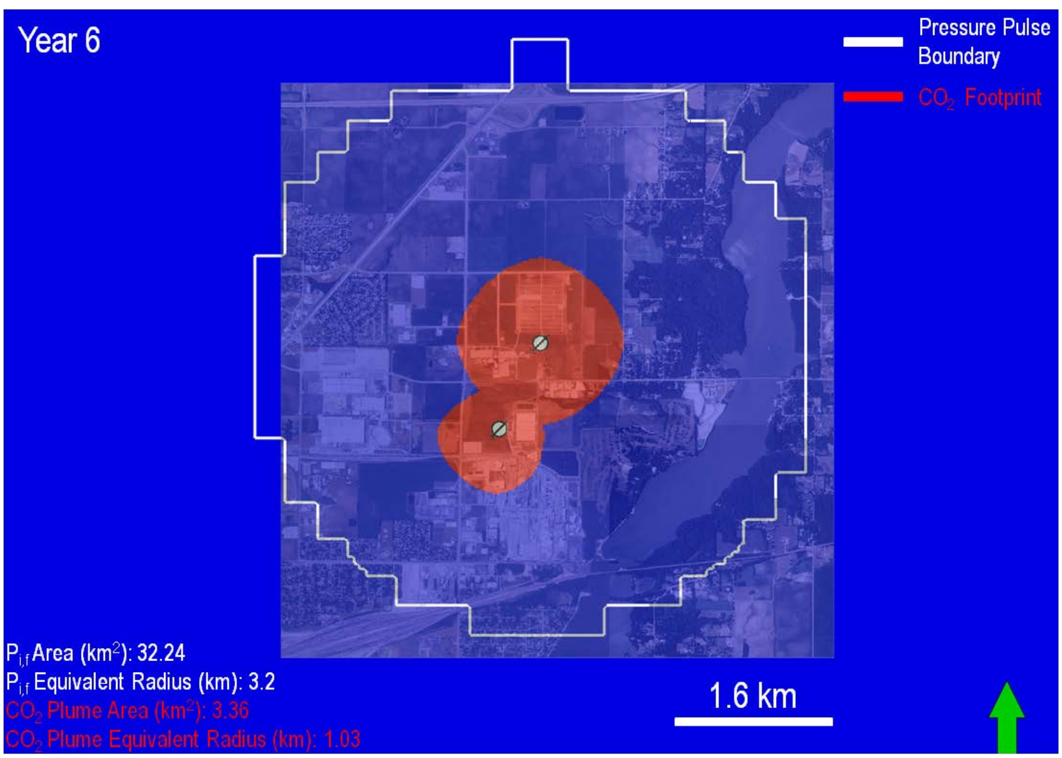


Figure 6 - 14 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 6.

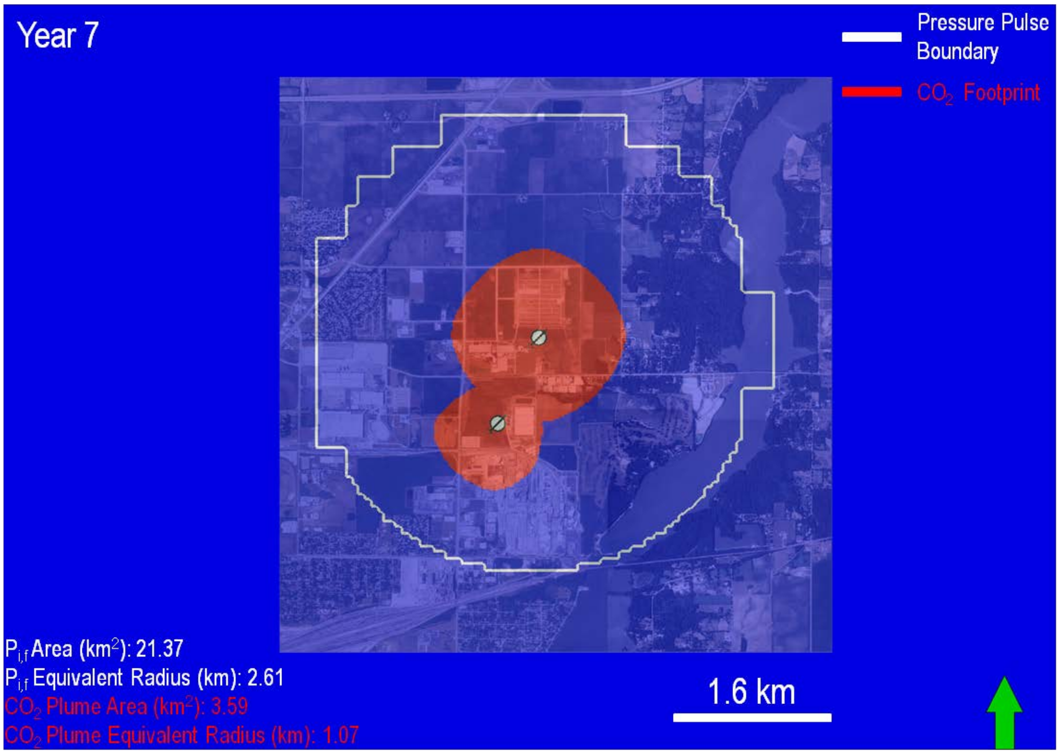


Figure 6 - 15 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 7.

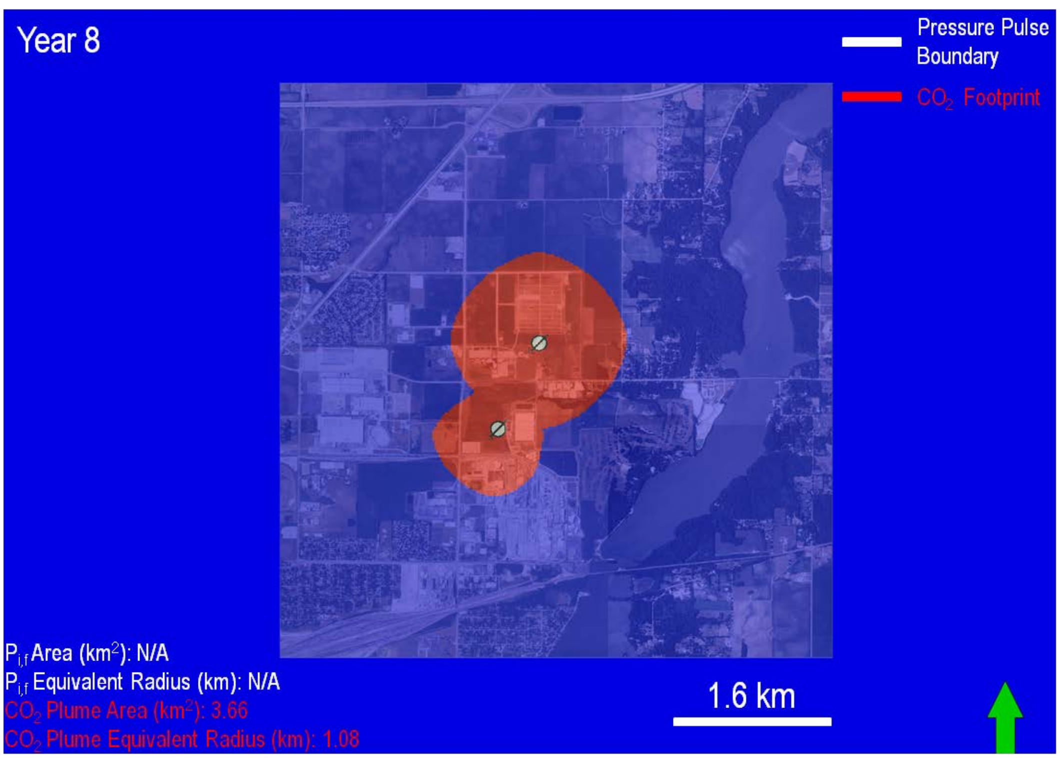


Figure 6 - 16 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 8.

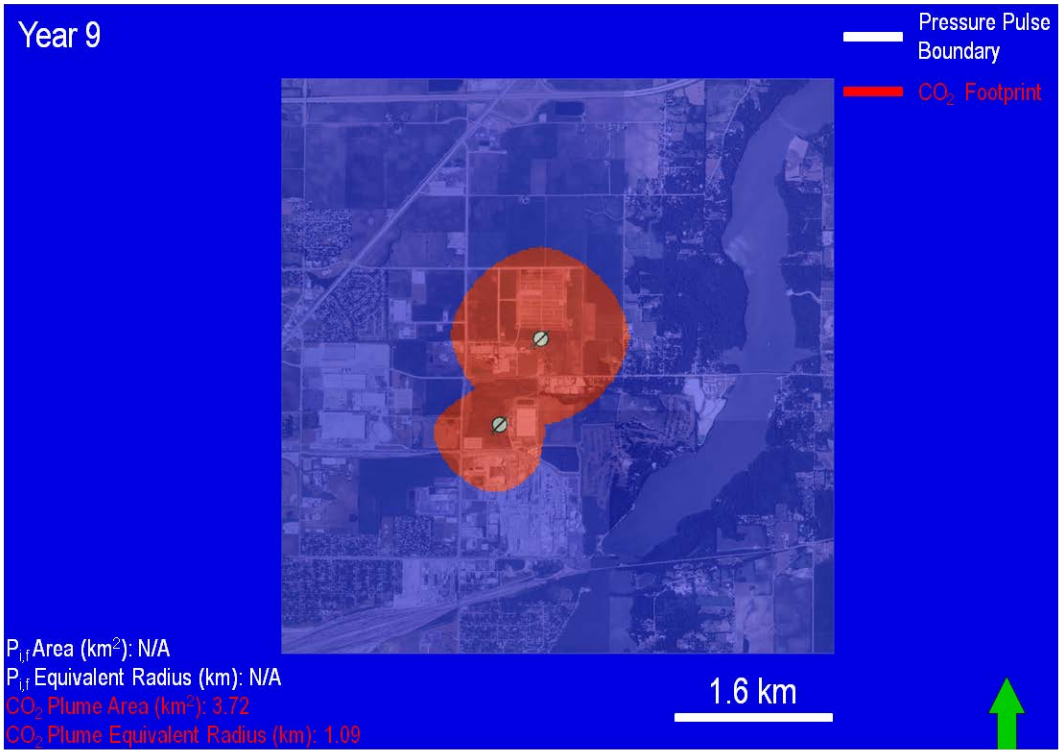


Figure 6 - 17 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 9.

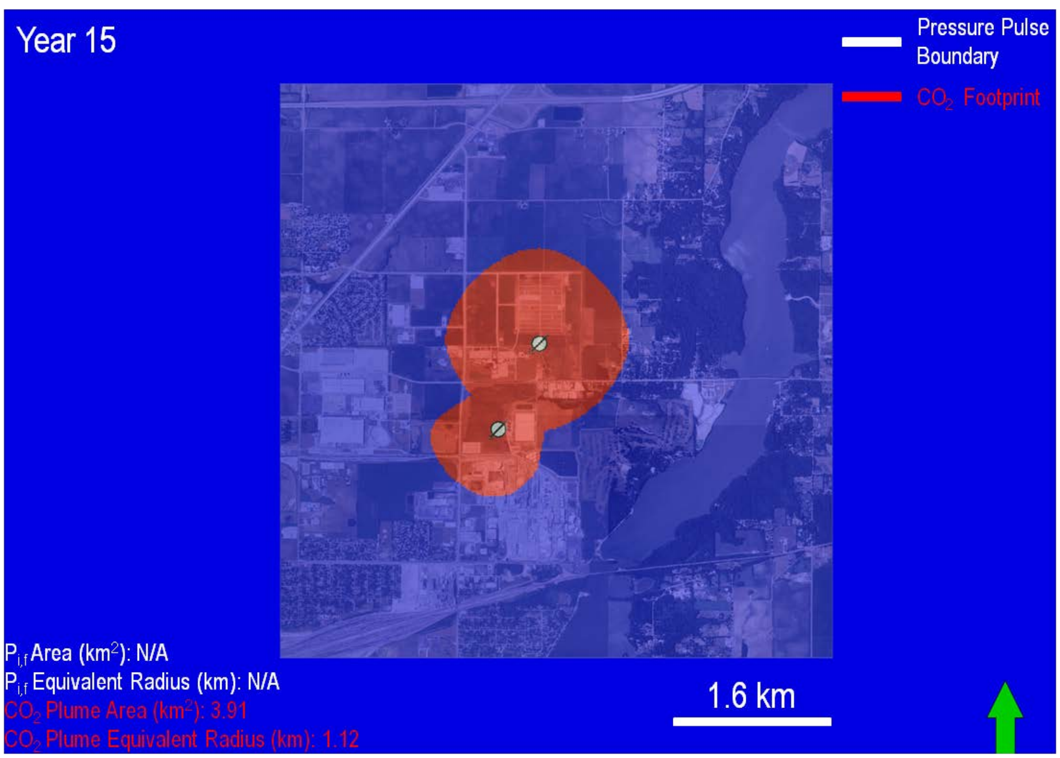


Figure 6 - 18 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 15.

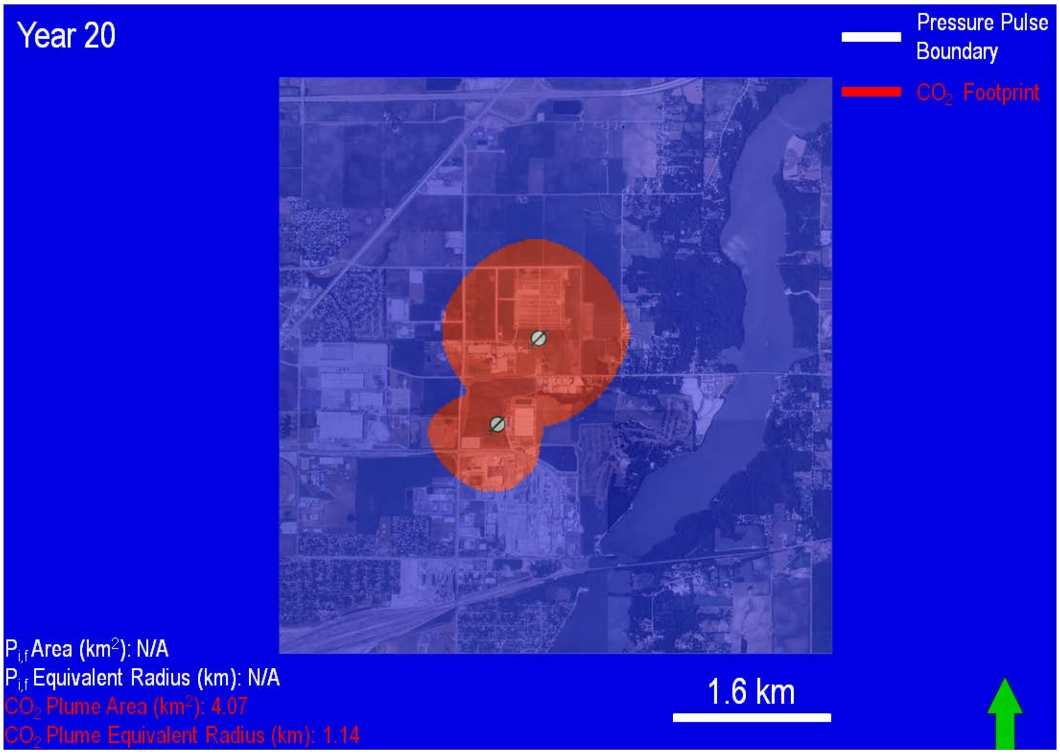


Figure 6 - 19 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 20.

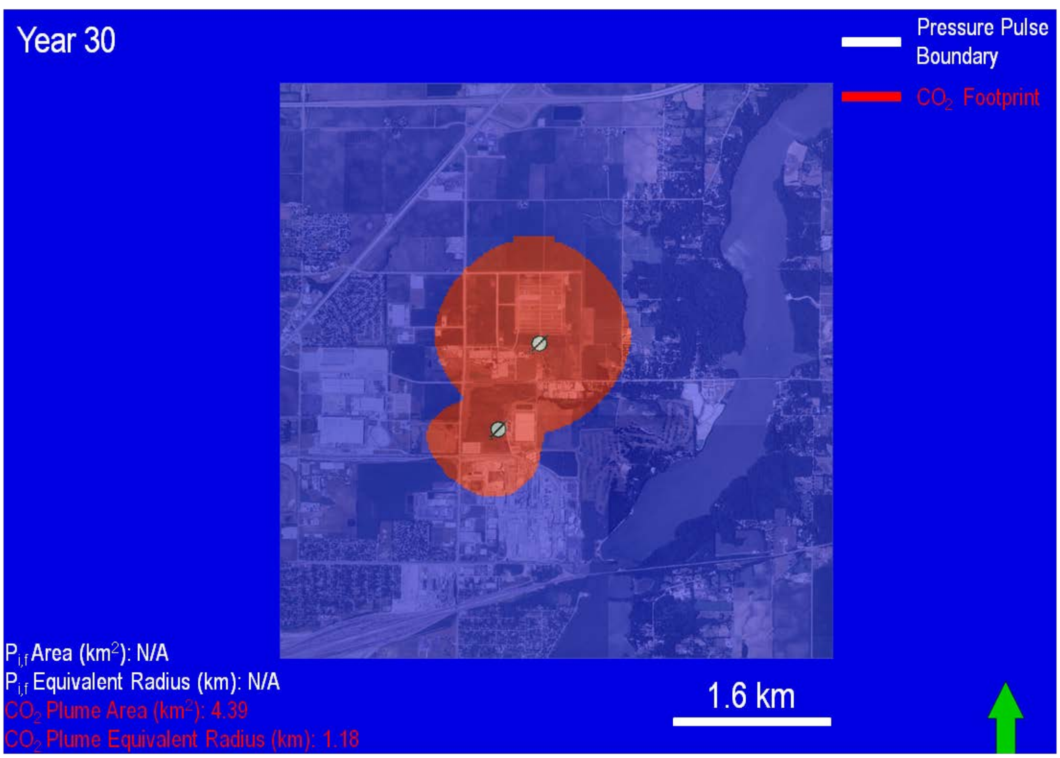


Figure 6 - 20 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 30.

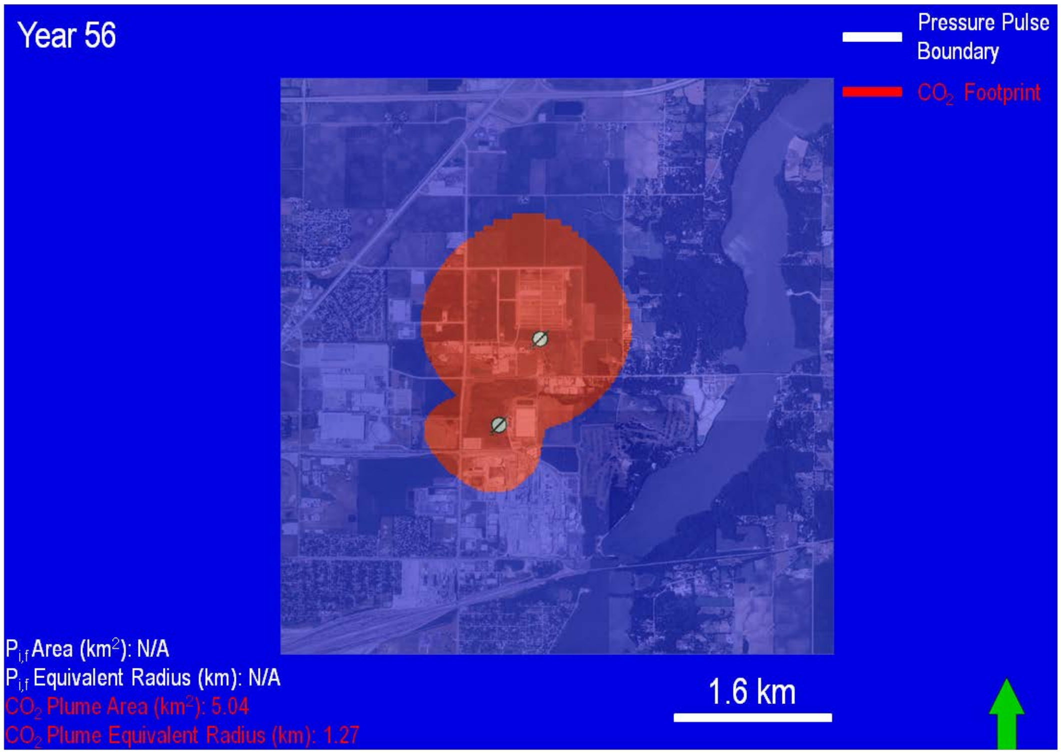


Figure 6 - 21 Map-view of pressure front (Pi,f) and CO2 plume footprints after simulated Year 56.

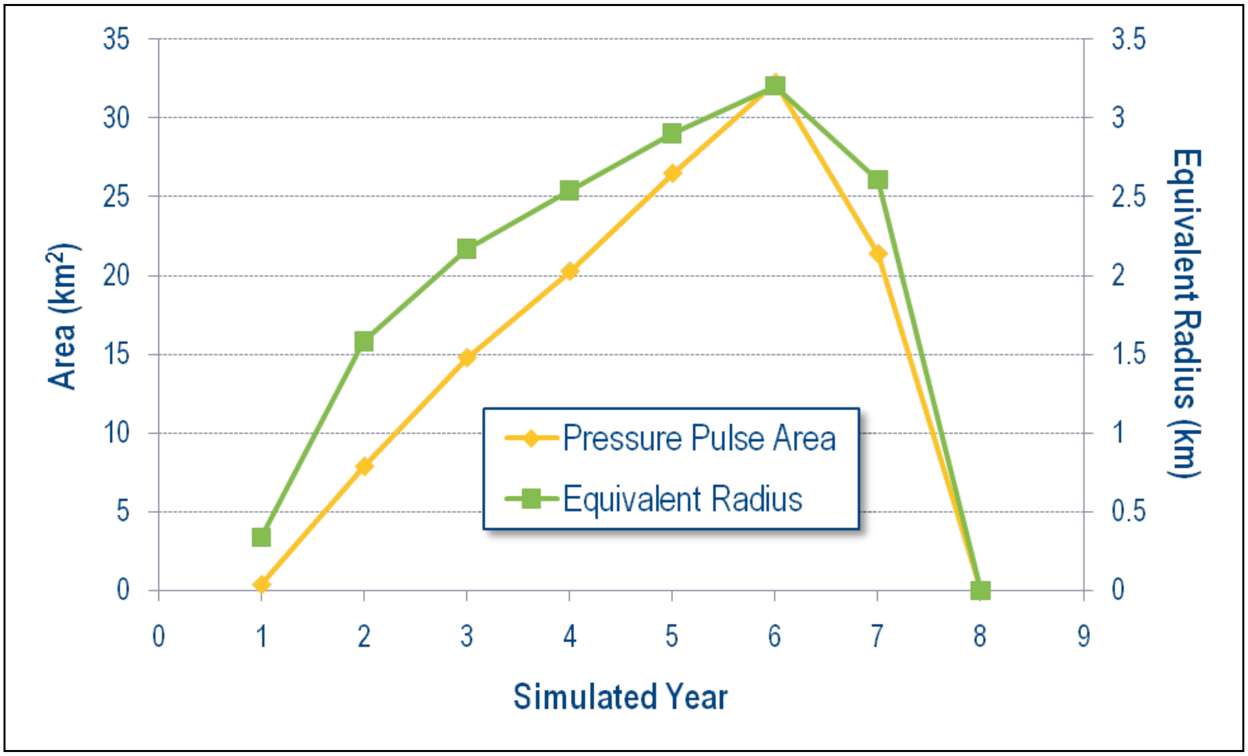


Figure 6 - 22 Graph of pressure front (Pi,f) area and equivalent radius throughout simulated time.

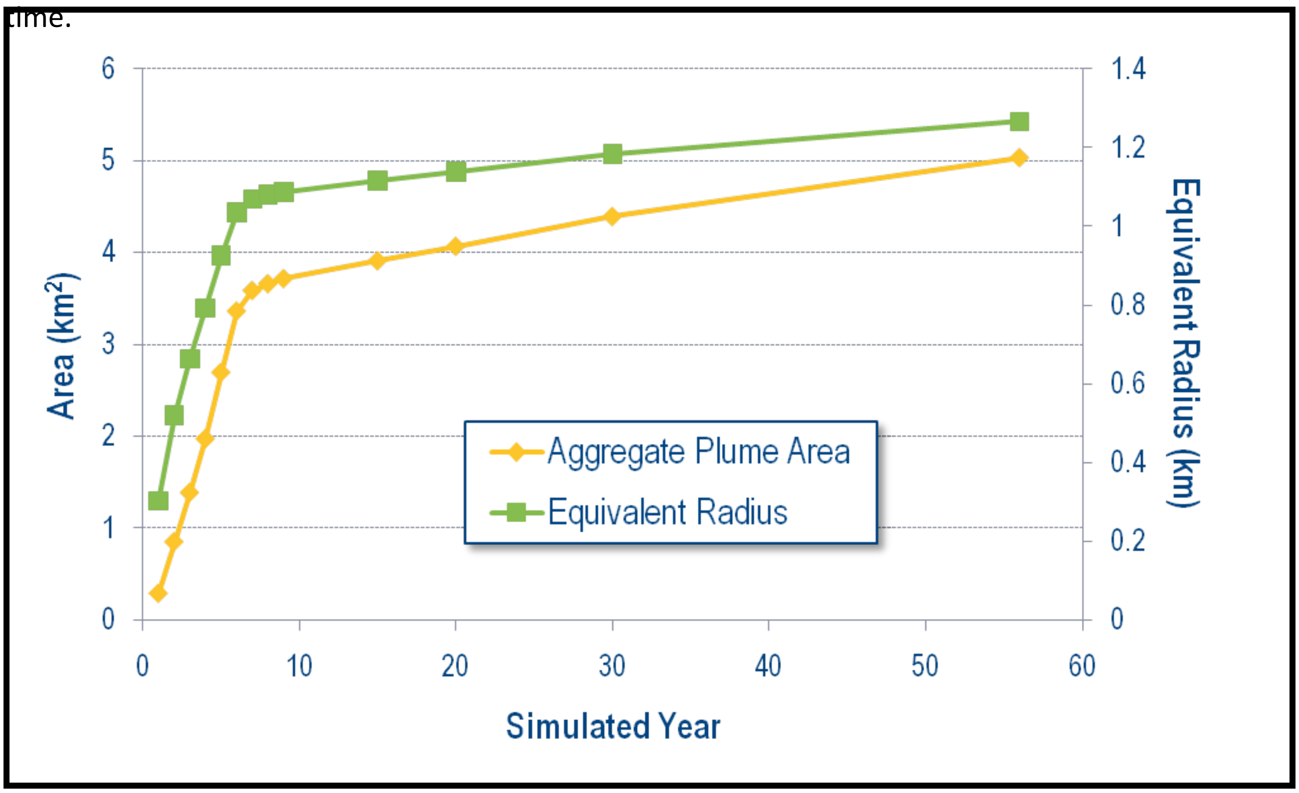


Figure 6 - 23 Graph of CO2 plume area and equivalent radius throughout simulated time.

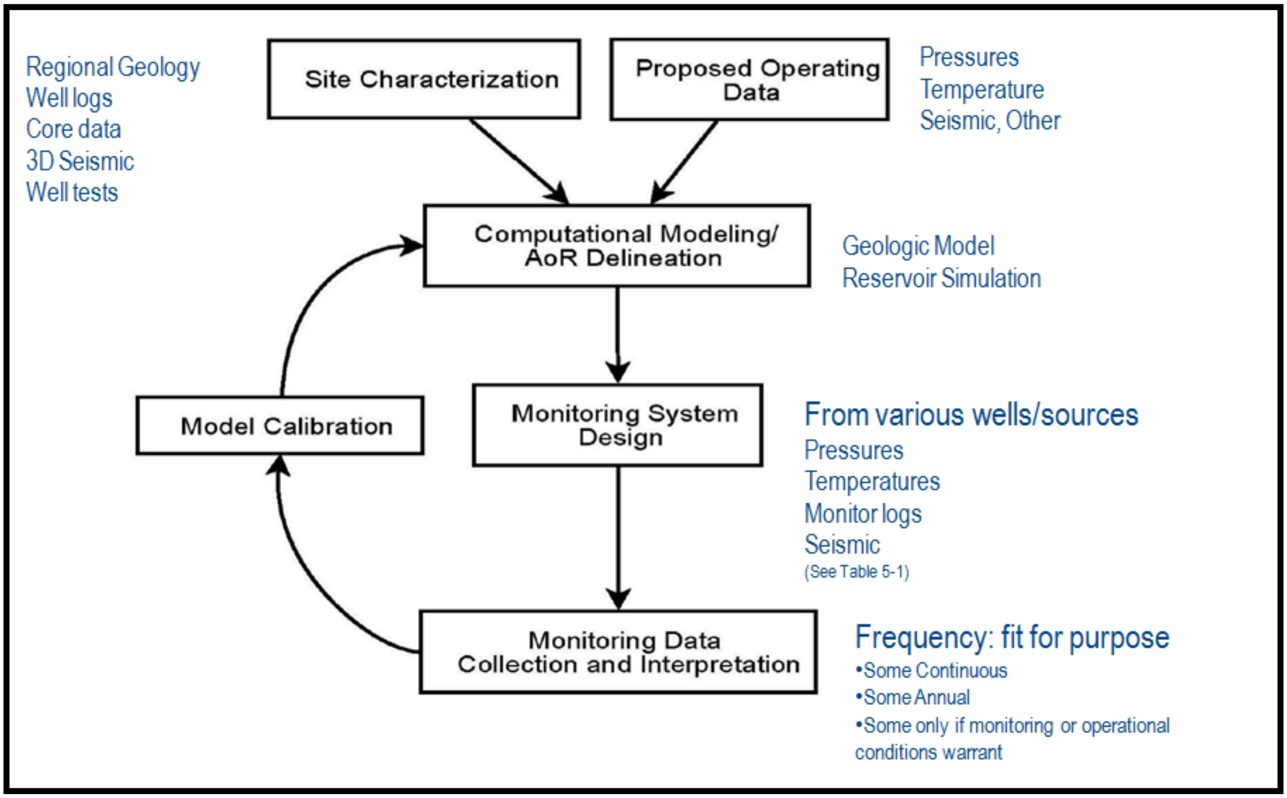


Figure 6 - 24 : AoR Corrective Action Plan Flowchart.

Reference: Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators, US EPA 2011

Table 6 - 1 Monitoring System Capability for IL-ICCS Injection Site.

	IL ICCS Wells			IL IBDP Wells		
	CCS#2	VW#2	GW#2	CCS#1	VW#1	GW#1
Approx. Depth (ft)	7200	7200	3500	7200	7200	3500
Approx. Distance from CCS#2 (ft)	0	3000	300	3950	2950	4050
Capable of obtaining:						
Mt. Simon pressure(s)/temperature(s)	yes	yes	no	yes	yes	no
Mt. Simon fluid sampling	no	yes	no	no	yes	no
Ironton Galesville pressure/temperature	no	no	no	no	yes	no
Ironton Galesville sampling	no	no	no	no	yes	no
St. Peter pressure/temperature	no	no	yes	no	no	no
St. Peter fluid sampling	no	no	yes	no	no	no
RST Logging (near wellbore CO_2 detection)	yes	yes	yes	yes	yes	yes
Seismic Imaging of CO_2 plume	no	no	yes	no	no	yes
Annulus Pressure at surface	yes	yes	no	yes	yes	no
Injection Pressure at surface	yes	no	no	yes	no	no

* Deeper formations only. Shallow USDW monitoring not included in this table

7. TESTING AND MONITORING PLAN

7.1 INJECTION WELL, CCS #1

7.1.1 CO_2 Composition Monitoring

Purpose

The purpose of this document is to provide a plan for sampling and analysis of carbon dioxide destined for sequestration at the Illinois Basin – Decatur Project site.

Parameters and Rationale

The CO_2 will typically be analyzed for the following constituents (the list of parameters to be analyzed may be altered as experience provides a clearer picture of the constituents of concern):

- CO_2 Identification (% v/v)
- Water Vapor, Moisture (ppm v/v)
- Oxygen (ppm v/v)

Volatile Sulfur Compounds (VSC, ppm v/v)
- Hydrogen Sulfide (H2S)
- Sulfur Dioxide (SO2)

Volatile Oxygenates (VOX, ppm v/v)
- Acetaldehyde
- Ethanol

Test Methods

Samples will be analyzed by a third party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization.

Sampling Methods

Grab samples will be collected in tedlar or equivalent bags from a sample port located downstream of the Primary Fermentation scrubber and the dehydration and compression station, but prior to the injection wellhead.

Frequency of Analysis

Samples will be collected and analyzed once every calendar quarter.

7.1.2 Monitoring Hardware at the Injection Well

Details of the various process monitoring sensors and gauges are summarized below and include the location of the device, the brand and model number, the device type (electrical or mechanical), and whether or not the device is continuously recording. All of the hardware is such that the operating range exceeds the expected maximum operating range of the injection well by more than 20 %.

Table 7-1 Monitoring hardware specifications.

Hardware	Make	Model	Type	Operation	Operating Range	Location
Surface Injection Pressure Gauge	ABB	264HSVKTA1L1N2	Electrical	Continuous Recording	0-4,000 psig	Installed directly into the wellhead tree cap port (PIT-009*)
Downhole Injection Pressure Gauge	Schlumberger	NDPG-CA (P/N 500897)	Electrical	Continuous Recording	0-10,000 psig	Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.
Casing-Tubing Annular Pressure Gauge			Electrical	Continuous Recording	0-600 psig	Mounted on the wellhead port open to the casing-tubing annulus.

Hardware	Make	Model	Type	Operation	Operating Range	Location
Flow meter	SCADASense	4203	Electrical	Continuous Recording	250-1,100 tonnes/day	Installed downstream of the multistage centrifugal pump (FIT-006+)
Surface Temperature Gauge	INOR	Meso-HX 70MEHX1001	Electrical	Continuous Recording	-40 – 185 °f	Installed downstream of the multistage centrifugal pump along the section of pipeline immediately upstream of the wellhead wing valve inlet and check valve. (TIT-009)
Downhole Temperature Gauge	Schlumberger	NDPG-CA (P/N 500897)	Electrical	Continuous Recording	0 – 212 °f	Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.

+Denotes the identifier on the Process Control Strategy Diagram Located in Appendix C

The annulus pump is a General Pump Co. Model 1321 triplex pump rated to 2,100 psi with a flow rate of 5.5 GPM. The pump is powered by a 3.0 HP Marathon 110/220v electric motor. The pump is controlled by two Barksdale Series 7000 pressure switches; one switch for low pressure to engage the pump and the other switch for high pressure to shut the pump down. The minimum annular pressure will be 400 psi in the annulus at the wellhead. Annulus pressure will be monitored at the ADM data control system. A 250 gallon, NaCl brine storage tank will be connected to the suction inlet of the pump. A hydrostatic tank level gauge will be installed in the brine storage tank with data fed back to the ADM monitoring system. The NaCl brine in the storage tank will be the same brine as in the annulus. The annular pressure will be monitored by the ADM control system using an ABB 264HSVKTA1L1N2 pressure gauge with a 150 psig operating range. Average annular pressure and fluid volumes changes will be recorded daily.

If there is a loss of electrical power to the annulus re-pressure system, annular pressure will be continued to be monitored by the pressure transducer or the pressure gauge. If the annulus pressure is stable and within the operating range, no action will be taken for power failures of 12 hours or less. If the power failure is expected to go beyond 12 hours or if the annulus pressure is falling below operating range, then a portable generator will be connected to the annulus re-pressure system. In an event where it is apparent that a positive pressure of at least 400 psig cannot be maintained, or that pressure above the packer cannot be maintained higher than the injection pressure into the injection zone, then injection will be shut down until repairs can be made.

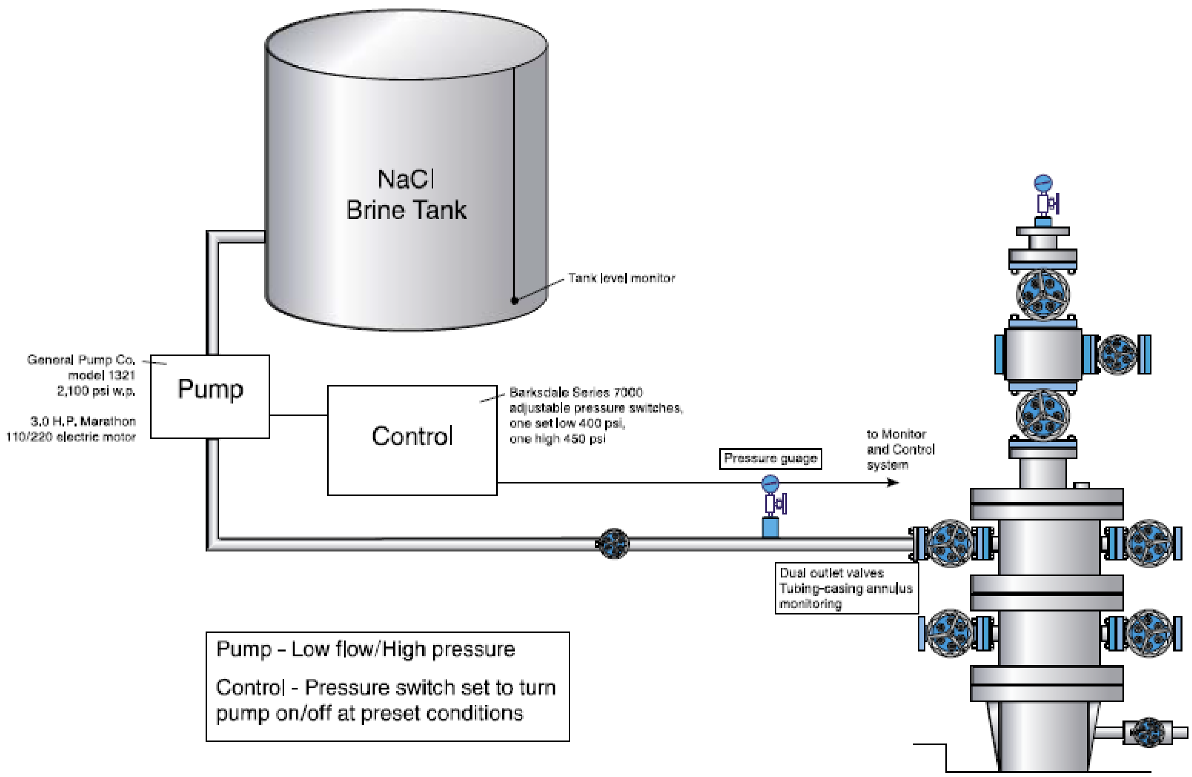


Figure 7-1 Annular protection system general layout.

7.1.3 Ambient Pressure Monitoring Procedure for Injection Well

Pressure falloff tests will be conducted annually during injection to calculate the annual ambient average reservoir pressure. The tests will be conducted near the end of the 1st, 2nd and 3rd (final) years of CO_2 injection. At a minimum, a planned pressure falloff test will be preceded by one week of continuous CO_2 injection at relatively constant rate. The well will be shut-in for at least four days or longer until adequate pressure transient data are measured and recorded to calculate the average pressure. These data will be measured using a surface readout down-hole gauge so a real-time decision on test duration can be made after the data are analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line

Pre-Injection Flow Period

Normal injection using the stream of CO_2 captured from the ADM facility will be used during the injection period preceding the shut-in portion of the falloff tests. The normal injection rate is estimated to be 1,000 tonnes/day. Prior to the falloff test this rate will be maintained. If this rate causes relatively large changes in bottom-hole pressure, the rate may be decreased. Injection will have occurred for 10 to 11 months prior to this test, but there may have been injection interruptions due to operations or testing. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis. These data will be measured using a surface readout down-hole gauge so a final decision on test duration can be made after the data are analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

Shut-in Period

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and down-hole recording memory restrictions will be eliminated, data will be collected at a high frequency (e.g., every five seconds) for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. Pressure sensors used for this test will be the wellhead sensors and a down-hole gauge for the pressure fall off test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (0.5% accuracy across full range). The wellhead pressure gauge range will be 0-4,000 psi. The downhole gauge range will be 0- 10,000 psi.

7.1.4 Injection Well Corrosion Monitoring Plan for Injection Well (CCS#1)

In order to monitor the corrosion potential of materials that will come in contact with the carbon dioxide stream, the following plan was developed.

Sample Description

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 7-2 below. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 7-2 List of samples with expected material type

Pipeline	CS XPI5L-X52
Long String Casing (Chrome)	13Cr80
Injection Tubing	13Cr85
PS3 Mandrel	13Cr80
Wellhead	13Cr80 or 85
Packers	13Cr80 or 85
Compression Components	316L SS

Sample Exposure

Each sample will be attached to an individual holder (Figure 7-2) and then inserted in a flow-through pipe arrangement (Figure 7-3). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The sample holders and location of the system will allow for continuation of injection during sample removal.

Figure 7-2 Coupon holder

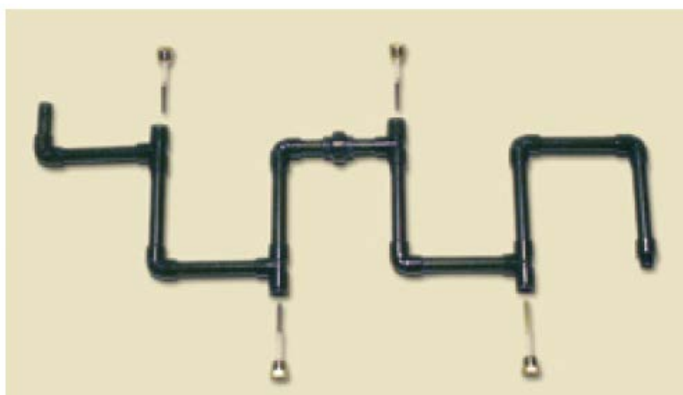


Figure 7-3 Flow-through Pipe arrangement

Sample Monitoring

The samples will be visually inspected and monitored on a quarterly basis for loss of mass, thickness, cracking, pitting, or other signs of corrosion. The sample holder will be removed from the CO_2 stream, and the samples will be removed from the holder for examination and measurements. Each coupon will be photographed and then be evaluated with the following precisions: Dimensional: 0.0001 inches Mass: 0.0001 grams. The coupons will then be examined microscopically at a minimum of 10 x power. Weights of the samples will be compared with original weights to determine if there is any weight gain or loss that would indicate degradation.

Reporting

Dimensional and mass data, along with a calculated corrosion rate (in mils/yr), will be submitted with the monthly operating report following the analysis.

7.1.5 MECHANICAL INTEGRITY TESTING

Mechanical integrity will be used to ensure integrity during the life of the well. The absence of significant leaks in the casing, injection tubing, and packer will be demonstrated using annulus pressure tests, conducted annually. The condition of the cement and casing will be verified using downhole logging techniques and tools. A cement inspection log will be run in the entire length of the long-string casing whenever the injection tubing is removed from the well or once in a five-year period if the tubing is removed more than once in the five years. An electromagnetic casing inspection log shall be run on the same schedule as the cement inspection log. The casing inspection log will be used to determine the thickness, external condition, and internal condition of the long string casing for its entire length. Notice of intent to conduct pressure tests, temperature logs, and any additional mechanical tests, logs, or inspections will be provided at least thirty (30) days prior to the demonstration of mechanical integrity.

ANNULAR PRESSURE TEST

The annulus pressure test shall be conducted in accordance with US EPA Region V's guidance: Determination Of The Mechanical Integrity Of Injection Wells. The annular pressure test will be run using the following procedure:

1. Stop injection and allow well to stabilize.
2. Confirm connectivity to and functionality of permanent gauges or install pressure gauge on annulus.
3. Rig up pump, pressurize annulus to 1000 psi.
4. Observe pressure change over a 1 hour period (taking a measurement at least every 10 minutes).
5. Any significant pressure drop will be investigated to verify that mechanical integrity is intact and corrected as necessary. Pressure test will be rerun following investigation / remediation to confirm integrity. The well will be deemed to have failed the annulus pressure test if a pressure change of greater than 3% occurs over the one-hour period.
6. Plot the gathered data and determine volume of fluid loss if any.
7. The data obtained, including recorded charts from the tests, shall be submitted as required by the permit.

ANNULUS PRESSURE MONITORING

The casing-tubing pressure will be monitored and recorded in real time. Pressure of the casing-tubing annulus is anticipated to be no lower than 400 psi. Any significant change of casing-tubing annulus pressure that can be related to mechanical integrity issues will be investigated as a possible leak in one of four areas:

1. Casing - from the surface to the packer
2. Tubing string - from the surface to the packer
3. Packer seal
4. Tree

TIME-LAPSE SIGMA LOGGING AND TEMPERATURE SURVEYS

An Initial time-lapse sigma and temperature logs were run after the well was constructed. Subsequent surveys will be used to demonstrate the absence of significant fluid movement into USDWs through vertical channels adjacent to the injection well. These tests shall be run biannually (every 24 months).

The procedure for running the time-lapse sigma logs is outlined below. The log will be run following a period of CO_2 injection, with the well in a static condition and fluid level to the Maquoketa Shale or higher.

1. Move in and rig up electric logging unit with lubricator
2. Run RST Sigma Log from TD through at least the Maquoketa Shale
3. Rig down the logging equipment
4. Process the data and compare to baseline log noting any changes in Sigma that can be attributed to CO_2

The temperature log will be run after the well has been in a state of injection for at least 6 hours prior to commencing operations to allow for accurate measurements. The approximate procedure to run the temperature log will be:

1. Move in and rig up an electrical logging unit with lubricator
2. Run a temperature survey from the Base of the Maquoketa Shale to the deepest point reachable in the Mt. Simon while injecting at a rate that allows for safe operations (should operation constraints or safety concerns not allow for a logging pass while injecting; an acceptable, alternate plan is to stop injecting immediately prior to the first logging pass).
3. Stop injection, pull tool back to shallow depth, wait 1 hour.
4. Run a temperature survey over the same interval as step 2.
5. Pull tool back to shallow depth, wait 2 hours
6. Run a temperature survey over the same interval as step 2.
7. Pull tool back to shallow depth, wait 2 hours
8. Run a temperature survey over the same interval as step 2
9. Evaluate data to determine if additional passes are needed.
10. Rig down the logging equipment
11. Overlay data and interpret which zones are open to injection.
12. The data obtained shall be submitted as required by the permit.

7.2 VERIFICATION WELL

7.2.1 SYSTEM OPERATION

Fluid pressure measurements can be collected from each zone in the monitoring well. Pressures can be obtained periodically at each measurement port using a single pressure probe, or more frequently using a string of probes which remain in the monitoring well so that pressures can be recorded automatically at the well, and accessed periodically either at the well site or via remote communication. Westbay MOSDAX Pressure Probes are used to collect the data and their specifications are:

Westbay MOSDAX Pressure Probe
Transducer full scale pressure range 0 psia to 5000 psia
Pressure accuracy ± 0.1% FS (CHRNL)
Temperature range 0°C to 70°C

The primary purging and well development was carried out prior to installation of the Westbay System. Following the installation of the Westbay System well components, a secondary purge was conducted using Westbay pumping ports.

The sampling probe incorporates a pressure transducer so fluid pressure measurements from each isolated sampling zone can be obtained during each sampling event. Pressure measurements may also be collected from each isolated zone independently of sampling.

Fluid samples can be obtained by lowering a sampling probe and sample container(s) to the desired measurement port coupling. The sampling probe operates in similar fashion to the pressure probe except that a formation brine sample is drawn through the measurement port coupling. Whenever the sampling probe is operated with the sampling valve closed, it functions the same as a pressure probe and provides analogous data.

When using a non-vented sample container, the fluid sample is maintained at formation pressure while the probe and container are returned to the top of the well. Once recovered, there are a variety of methods of handling the sample:

- the sample may be depressurized and decanted into alternate containers for storage and transport
- the sample container may be sealed and transported (inside a DOT approved transport container) to a laboratory with the fluid maintained at formation pressure, or
- the sample may be transferred under pressure into alternate pressure containers for storage and transport

In addition, the security of the well and the Westbay system will be supported throughout sampling activities by incorporating the following procedures:

- Work to be done during daylight hours
- Check and record pressure on tubing and bleed down any excess pressure
- Selectively release each pressure probe from its corresponding Westbay port
- Remove pressure probes (using installed winch system) from well via wireline and winch, noting and recording fluid level upon removal
- Reenter tubing with the sampling probe, note and record fluid level upon entry, obtain sample from target zone designated zone
- Remove sampling probe noting and recording fluid level
- Repeat until all samples have been recovered
- Any significant fluid level change (100 feet) observed during sampling operations will be noted and recorded, and will trigger investigation
- Reinstall pressure probes, note and record fluid levels
- Note final fluid level and include on report. This is the fluid that will be used as a baseline comparison to the next event.

If there is any delay during the sampling event (e.g. repairs to the system, the fluid in the tubing will be measured once per day.

The advantages of this discrete sampling method are summarized as follows:

1. The sample is drawn directly from a measurement port immediately adjacent to the perforations. Therefore, there is no need for pumping a multiple well volumes of fluid prior to collecting each sample as is done with some other sampling methodologies . Because there is limited fluid removal prior to sampling, the sample is obtained with minimal distortion of the natural formation water flow regime.

2. The reduced need for pumping means samples can be obtained quicker, even in relatively low permeability intervals.

3. The sample travels only a short distance into the sample container, typically from 1 to 2 feet, regardless of depth.

4. The risk and cost of storing and disposing of purge fluids is virtually eliminated

7.2.2 WESTBAY MONITORING PLAN

Under normal operating conditions continuous monitoring of fluid pressure/temperature will be carried out using the Westbay automated data-logging system with pressure probes in ten monitoring zones and one quality assurance (QA) zone. When operations, such as sampling or logging, require removal of the automated data-logging system, manually operated monitoring can be carried out using wireline deployed probes.

7.2.3 WESTBAY MECHANICAL INTEGRITY TESTING

The mechanical integrity of the well will be established to verify the absence of significant leaks. Downhole and surface pressures, along with the casing-tubing annulus pressure, will be monitored and recorded. The annulus above the uppermost packer will also be monitored for pressure changes. This annulus will be pressure tested to 300 psi for one hour, with a maximum of 3% leakoff, allowed at least once per year. The results of the test will be reported. In addition the following section describes the mechanical integrity testing of the wellbore across the multi-level monitoring system.

The Westbay System is designed to incorporate a high degree of quality assurance testing and verification to confirm mechanical integrity of the system and the presence of packer seals between monitoring zones. Pressure monitoring is intended to be carried out at multiple levels within the Mt. Simon injection horizon, as well as at selected intervals in porous and permeable stratigraphic units immediately overlying the cap rock.

A quality assurance (QA) and monitoring program will be utilized to confirm the presence of annular seals between monitoring zones, and particularly to document the performance of the annular seals which isolate the individual zones and also prevent the movement of fluids into the overlying stratigraphic units. The Westbay System is compatible with the expected site subsurface environment (brine and CO_2) and elastomers present in the system are CO_2 resistant.

A loss of mechanical integrity or component failure leading to the potential for vertical migration of fluid in the annulus is not expected. However, a number of methods, including wireline and pressure and temperature measurements, will be used to monitor system integrity and to verify the absence of vertical fluid movement within the well. These methods were implemented during Westbay System installation and will continue during ongoing monitoring well operations, as described below. During the installation process, a thorough QA procedure is followed to document Westbay System performance, including:

- testing the hydraulic integrity of each tubing joint as the tubing string is assembled, providing baseline data confirming that the assembled joint is sealed and not a pathway for vertical movement of formation fluids

- testing the hydraulic integrity of the entire Westbay System tubing once the tubing has been lowered into place, again providing baseline data confirming that the tubing string is sealed and not a pathway for vertical movement of formation fluids

- testing and documenting the proper operation of each of the measurement ports (the ports used for pressure monitoring and sampling) by carrying out a pre-inflation pressure profile

- documentation of inflation performance of each packer as it was independently and individually inflated with fresh water (the inflation pressure and volume was measured and recorded, and the correct function of each packer was documented)

After the packers were inflated and seals were established between the perforated zones, fluid pressure profiles and cased-hole logging was carried out to establish baseline conditions of the well. Fluid pressure profiles were carried out using a wireline operated pressure probe with transducer. The annular fluid pressure was measured at each measurement port.

A measurement port is adjacent to each packer in the Westbay System. The fluid pressures can be measured and recorded in each perforated zone, as well as in each of the shut-in (cased) sections of the well between each perforated zone. The blank zones between perforations are referred to as “QA Zones” (Quality Assurance Zones). Each QA Zone consists of two packers and the blank (not perforated) casing between them. Having no connection to the formation, pressure data from such zones can be used to document the continued sealing performance of the packers. The presence of a persistent measurable pressure difference across a packer indicates the presence of a positive annular seal. The pressure data collected from all of the perforated zones and the QA zones will be used to provide baseline data, and will be compared to the pre-inflation profiles to help document the presence of seals between perforations in the annular space.

Cased-hole logging tools can pass through the Westbay tubing and log the near-wellbore environment behind the well casing. The cased-hole logs are not adversely affected by the Westbay System, so the tubing does not need to be removed during the time-lapse sigma and other cased-hole wireline logging techniques. Evaluation of baseline pressure data and cased-hole logging data collected from the Westbay System during the pre-injection period is an integral part of establishing baseline and will be used to assess data collected during the injection and post-injection phases of the project.

The Westbay System will be used for automated data logging of fluid pressure/temperature from select monitoring zones, as well as manual collection of fluid samples, measurement of fluid pressure/temperature and testing. Manual operations require removal of the automated data logging items. Routine monitoring activities that will be used as part of the Mechanical Integrity Testing System are described below:

1. Monitoring of the pressure or the absence of pressure inside the casing/tubing annulus above the top Westbay System packer will be carried out continuously by means of a pressure gauge at the wellhead. Any unexpected changes in the annulus pressure will be investigated to ensure that it is not an indication of the loss of integrity.

2. Under normal operating conditions monitoring of the fluid level inside the Westbay System tubing will be carried out continuously using a pressure sensor included with the automated data logging system. Manual readings of the fluid level inside the Westbay System will be collected as part of standard operating procedures for all other activities. An unexpected change in the water level inside the Westbay System tubing will be investigated to ensure that it is not indication of a loss of hydraulic integrity of the Westbay System tubing.

3. Continuous measurement and recording of fluid pressure/temperature will be carried out using the Westbay automated data logging system, which consists of pressure probes located at each of the monitoring zones. Observed differential pressures between perforated zones will provide real-time confirmation of effective annular seals between monitoring zones. As part of the Mechanical Integrity Testing System, an additional pressure probe will be used to continuously measure and record fluid pressure in one of the redundant QA zones located adjacent to the Eau Claire shale. Continuous fluid pressure measurements from the QA zone during and after CO_2 injection will be compared to background data trends and the persistent presence of a pressure differences (corrected for depth and fluid density) between the QA Zone and the adjacent perforated zone. An unexpected change of this corrected pressure difference to less than 10 psi will be investigated to confirm that it is not an indication of a possible loss of packer seal. The value of 10 psi was selected based on the accuracy specification of the Westbay MOSDAX pressure probe (described above).

4. The automated data logging system may be removed at regular intervals for maintenance and servicing, as well as for any other planned activities such as sampling. As part of standard Westbay System operating procedures, fluid pressure and temperature will be measured manually from all monitoring zones following removal of the automated system, and before replacement of the automated system. Should the system be removed longer than 4 weeks manual pressures in at least one QA zone will be taken in the following 2 weeks and every 6 week thereafter until the system is reinstalled. The pressure/temperature measurements will be compared to background data and other previous profiles.

5. Cased-hole logs will be run in the event of a compromised seal where CO_2 enters the annulus, the RST tool will be used to identify unexpected CO_2 independently of Westbay System measurements.

To verify the "absence of significant fluid movement," time-lapse formation sigma logs will be run and data recorded continuously from the deepest reachable point in the Mt. Simon to, at a minimum, the Maquoketa Shale (the lowest alternative confining zone). These logs were run before CO_2 injection to establish a pre-CO_2 baseline. The logs will be run under static conditions, presumably with tubing in the hole, although valid data can and will be acquired should tubing be pulled for any unforeseen reasons. During CO_2 injection, the evaluation will also include a temperature log to further detect fluid movement. The temperature log will be run over the same intervals and at the same conditions as the sigma logs. Should either evaluation method (sigma or temperature log) detect significant fluid movement above the seal, oxygen activation logging methods may be used to further quantify the flow and aid in establishing a remediation plan. Details of Schlumberger's version of these tools are described below:

RESERVOIR SATURATION TOOL (RST)

The RSTPro* Reservoir Saturation Tool helps manage complexity by delivering reliable, accurate data. Run on the PS Platform string, with its suite of cased hole reservoir evaluation and production logging services, the RSTPro* tool uses pulsed neutron techniques to determine reservoir saturation, lithology, porosity, and borehole fluid profiles. This information is used to identify bypassed hydrocarbons, evaluate and monitor reserves in mixed salinity and gas environments, perform formation evaluation behind casing, and diagnose three-phase flow independently of well deviation.

An electronic generator in the RSTPro* tool emits high-energy (14-MeV) neutrons in precisely controlled bursts. A neutron interacts with surrounding nuclei, losing energy until it is captured. In many of these interactions, the nucleus emits one or more gamma rays of characteristic energy, which are detected in the tool by two high-efficiency scintillators. High-speed digital signal electronics process and record both the gamma ray energy and its time of arrival relative to the start of the neutron burst. Exclusive spectral analysis algorithms transform the gamma ray energy and time data into concentrations of elements (relative elemental yields).

In sigma mode, the RSTPro* tool measures formation sigma, porosity, and borehole salinity using an optimized Dual-Burst* thermal decay time sequence. The two principal applications of this measurement are saturation evaluation, which relies on measurement accuracy, and time-lapse monitoring, where sensitivity is determined by measurement repeatability. A higher degree of accuracy in the formation sigma measurement is achieved by combining high-fidelity environmental correction with an extensive laboratory characterization database. The accuracy of RSTPro formation sigma is 0.22 cu (capture units) for characterized environments and has been verified in the Callisto and American Petroleum Institute industry-standard formations. Formation porosity and borehole salinity are either computed in the same pass or input by the user. Exceptional measurement repeatability makes the RSTPro tool more sensitive to minute changes in reservoir saturation during time-lapse monitoring. The gains in repeatability and tool stability are the result of higher neutron output and sensor regulation loops. At the typical logging speed of 900 ft/h [275 m/h] for time-lapse monitoring, RSTPro repeatability is 0.21 cu.

WATER VELOCITY (OXYGEN ACTIVATION LOGGING)

The RSTPro WFL* Water Flow Log measures water velocity by using the principle of oxygen activation. Gamma ray energy discrimination and tool shielding reduce the background from stationary activation, improving sensitivity in low-signal environments such as flow behind casing.

7.3 GROUNDWATER MONITORING OF THE LOWERMOST USDW

As approved by the Illinois EPA under the Class I UIC permit application, a lowermost USDW groundwater monitoring program was initiated at the Illinois Basin - Decatur Project site. It is proposed that this program be continued as part of the Class VI permit application. A description of the existing monitoring program is given below.

7.3.1 EXISTING GROUNDWATER MONITORING PROGRAM

In Macon County, Quaternary sand and gravel deposits are used as a source of drinking water for most private water wells. Available information indicates that these sand and gravel deposits are not uniformly distributed (Larson et al., 2003, Figure 7-4) and may not be found continuously beneath the project site. Some private water wells are also completed in bedrock, but water quality deteriorates rapidly with depth. Most water wells within 2.5 miles of the injection well have depths ranging from 70 to 101 feet (Figure 7-5), which coincides with the depth of the upper Glasford aquifer (Figure 7-6). On December 2, 2009, the Illinois EPA specified the lowermost USDW to be the Pennsylvanian bedrock (i.e., below the Quaternary deposits) in the vicinity of the IBDP site.

Four regulatory compliance wells were drilled and constructed by the Illinois State Geological Survey (ISGS) during April and May 2010 (Figure 7-7). Wells are generally about 140 feet deep and constructed of two-inch diameter polyvinylchloride (PVC) materials with 10-foot screened intervals (Table 7-3). Two monitoring wells were located near the injection well. When the monitoring wells were being constructed, the injection well was the only known penetration of the caprock in the vicinity and thus represented an area of greater risk for leakage. Well placement to the north of the injection pad was guided by the expected movement of the CO_2 plume northward as influenced by the injection process and geologic dip of Precambrian and Mt. Simon strata (see figures in Section 2 of this application).

Table 7-3. Selected construction information for existing USDW monitoring wells

Well name	**ISGS/API well number**	**Illinois State Plane Coordinates** (ft)		**Top of riser pipe** (ft above MSL)	**Approximate distance to injection well** (ft)	**Depth of well bottom** (ft BGS)	**Screened interval*** (ft above MSL)	**Date installed**
		Northing	Easting					
G101	121152344600	1169622.3	827089.8	675.59	50	141.6	532 to 542	5/5/2010
G102	121152345000	1169624.6	827037.1	676.13	43	142.5	531 to 541	5/11/2010
G103	121152344000	1169774.3	826911.2	675.28	237	141.6	532 to 542	4/27/2010
G104	121152344300	1171119.3	826003.4	684.52	1858	139.6	543 to 553	5/24/2010

*values are rounded to the nearest foot

During drilling, continuous cores were collected at selected monitoring well locations and are archived at the Illinois State Geological Survey. Field descriptions of the cores were made and used to select monitoring intervals for each well. Sand pack was used in intervals as specified by the Illinois EPA with a maximum sand pack of 5 feet above the top of the screen. Bentonite was used to fill the annular space above the sand pack to land surface. Surface completion included a locked well protector set in concrete. Figure 7-8 shows a representative, as-built well completion report of one of the monitoring wells, G101. All other monitoring wells were constructed with similar materials and methods. The elevations of the monitoring wells were determined by level surveying, based on the known elevation of a local benchmark. Prior to implementing the sampling schedule, all wells were developed. After well development was completed, dedicated bladder pumps and pressure transducers were installed in each well and quarterly monitoring of 11 groundwater compliance parameters was initiated on October 29, 2010 per methods described in Appendix H of the approved Class I permit application.

Since January 2011, quarterly groundwater reports have been submitted to the Illinois EPA to characterize groundwater quality on a periodic basis to ensure that the injection activities are not affecting in the water quality of the lowermost USDW. Current field and indicator parameters are as follows:

Field Parameters:

- pH
- Specific Conductance
- Temperature
- Dissolved Oxygen

Indicator Parameters:

- Alkalinity
- Bromide
- Calcium
- Chloride
- Sodium
- Total CO_2

All indicator parameters of interest are inorganic and have been selected based on known chemical reactions of CO_2 in aqueous media. These parameters are expected to be key indicators in determining whether injected CO_2 has or has not impacted groundwater quality either 1) directly by introduction of CO_2 into shallow groundwater or 2) indirectly by CO_2-induced migration of groundwater with differing chemical compositions (e.g., brine) into shallow groundwater.

7.3.2 USDW WELL SAMPLING, ANALYTICAL METHODS, AND REPORTING

Sample Containers

All sample bottles will be new. Sample bottles and bags will be used as received from the vendor or contract analytical laboratory or cleaned prior to use as appropriate for the analyte of interest.

Well Purging and Sampling

Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities. Dedicated pumps (e.g., bladder pumps) will be used in each monitoring well to minimize potential cross contamination between wells.

Groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell consistent with standard methods (e.g., APHA, 2005) given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored during well purging and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table 7-4. It is anticipated that purging will primarily be conducted based on stabilization of the field parameters using a low-flow method. However, conditions (e.g., low well productivity) may require the use of other methods consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow through cell is not used, field parameters will be measured in grab samples.

Table 7-4. Stabilization criteria for groundwater monitoring well purging

FIELD PARAMETER	STABILIZATION CRITERIA
pH	+ / - 0.2 units
Temperature	+ / - 1° C
Specific Conductance	+ / - 3% of reading in µS/cm
Dissolved Oxygen	+ / - 10% of reading or 0.3 mg/L whichever is greater

Samples will be filtered through 0.45 µm flow-through filters as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 milliliters of well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis. Sample preservation techniques (Table 7-5) are consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4° C until analysis.

Table 7-5. Sample preservation and containers

Analyte	Preservation[1]	Holding Time[1]	Container[1]	Method
Alkalinity	Filtration, 4° C	In field, 14 days	HDPE bottle	EPA 310.1 APHA[2] 2320
Dissolved Anions: Bromide, Chloride	Filtration, 4° C	28 days	HDPE bottle	EPA 300.0 APHA 4110B
Dissolved Metals: Calcium, Sodium	Filtration, 4° C, HNO_3 < pH 2	6 months	HDPE bottle	EPA 200.8 APHA 3120B
Total CO_2	Filtration, 4° C	14 days	HDPE bottle	APHA 4500-CO_2D Orion, 1990 or ASTM D513-06

Note 1: USEPA, Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020

Note 2: American Public Health Association, Standard Methods for the Examination of Water and Wastewater

Sample Analysis

Sample analysis will be performed by a National Environmental Laboratory Accreditation Program (NELAP) accredited laboratory except in the case of Total CO_2. Anion concentrations will be determined by ion chromatography (e.g., O'Dell et al., 1984, EPA Method 300.0), and cation concentrations will be determined by inductively coupled plasma (ICP) spectrophotometry, (e.g., EPA Method 200.8; APHA, 2005). Alkalinity will be determined using

APHA Method 2320. Total CO_2 concentrations will be determined preferentially by coulometry per ASTM D513-06 or alternatively by other methods (e.g., Orion, 1990; APHA, 2005).

Quality Assurance/Quality Control (QA/QC)

Field quality assurance will primarily include periodic field duplicates and field blanks. A minimum of one field duplicate and one field blank will be used per sampling event. Additional field QA/QC measures will be implemented according to ASTM Method D7069-04 (2004) as needed based on data analysis of historical results and laboratory performance during the monitoring program.

Sample Chain of Custody

All sample bottles will be labeled with durable labels and indelible markings. A unique sample identification number, sampling date, and analyte(s) will be recorded on the sample bottles and sampling records will be kept for each well. Sampling records (e.g., a field logbook, individual well sampling sheet) will indicate the sampling personnel, date, time, sample location/well, unique sample identification number, collection procedure, measured field parameters, and additional comments as needed.

A chain-of-custody record shall be completed and accompany every sample or group of samples collected during an individual sampling event to track sample custody. This record should include: sampler name(s), their affiliation, address, phone number, project identification and project location, sample(s) identification number(s), sampling date and time, signature of person(s) involved in chain-of-custody possession, and remarks regarding sample(s). Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging and shipping of samples. Immediately upon sample collection, containers shall be placed in an insulated cooler and cooled to 4 degrees Celsius. Samples will either be shipped or hand delivered. Shipment priority will be determined by the holding times or need to expedite sample analysis. Upon receipt at the laboratory, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.

Groundwater Quality Evaluation and Reporting

Data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet with periodic data review and analysis. Copies of analytical reports from the NELAP laboratory will be kept on file at the ISGS for the duration of the project. Analytical results from the NELAP laboratory will be reported quarterly to the USEPA based on the approved UIC permit conditions. In the quarterly reports, data will be presented in graphical and tabular formats as appropriate to characterize general groundwater quality and identify intrawell variability with time. After sufficient data have been collected, additional methods consistent with the USEPA 2009 Unified Guidance (USEPA, 2009) may be used to evaluate intrawell variations for groundwater constituents to evaluate if significant changes have occurred that could be the result of CO_2 or brine seepage.

7.4 PERIODIC REVIEW

The testing and monitoring plan shall be periodically reviewed ensure that monitoring is taking place at an appropriate interval and at appropriate locations, based on the AoR. The Review will occur no less frequently than every 5 years. An amended testing and monitoring plan, or demonstration that no revision is necessary, shall be submitted to the permitting agency.

(1) Within one year of an area of review re-evaluation; or

(2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the permitting agency; or

(3) When required by the permitting agency.

7.5 REPORTING

Monitoring data will be reported on a monthly basis to IEPA and on an schedule established to the US EPA.

INJECTION WELL DATA REPORTING

The data reported from the injection well monitoring will be comprised of:

1. Daily value for total mass and daily maximum and minimum values for annulus pressure(s), injection pressure, and flow rate.
2. Weekly averages for annulus pressures, injection pressure and flow.
3. The number of times the injection well is started up during each day
4. Total hours of injection each day
5. Total mass injected to date
6. Monthly summary of:
    a. maximum, minimum, and average values for annulus pressures, injection pressure, and flow rate.
    b. total mass injected

c. total number of injection well startups 1150155136 – Macon County ADM Company Log No. UIC-143-M-2 Page 13 of 69

7. A copy of the operating charts for the month for:
   a) annulus pressures
   b) injection pressure
   c) flow rate

operating charts will be generated from data. The charts generated will provide shall be an accurate representation of the electronic data and provide sufficient resolution to represent the condition of the well during operation. format.

Other monitoring and testing results in monthly reports

The results of any of the following tests or monitoring will be reported IEPA with the second monthly report after completion of the test or work and to US EPA on a schedule established by the permit. Other monitoring and testing results that will be reported include:

1. Periodic tests of mechanical integrity.

2. Results of injection stream composition analysis

3. Copies of any logs run on a well, submitted with a log analysis.

4. Any other test conducted.

5. Any well work over.

6. Maintenance performed on monitoring devices or well components.

7. Changes of gauges, pipes, and other well components and monitoring devices.

8. Changes in the type of annulus fluid. 1150155136 – Macon County ADM Company Log No. UIC-143-M-2 Page 14 of 69

9. Addition or removal of annulus fluids.

10. Summary of annular fluid level fluctuations.

11. Ambient pressure monitoring results.

12. Seismic surveys (not required for IEPA)

13. Other monitoring as required by the Class VI permit (not required for IEPA)

7.6 QUALITY ASSURANCE

Data collected by the operator for testing and monitoring of the Class VI injection well will be subject to verification by an independent laboratory or, if compiled in-house, will be subject to verification using in-house quality assurance procedures.

Testing and monitoring data to be submitted to the permitting agency will be reviewed by the operator prior to submission. Any data inaccuracies will be noted and checked to determine the error source (e.g. monitoring equipment malfunction, data entry error, lab reporting error, etc.) and correct the error source as soon as possible.

7.7 REFERENCES

APHA, 2005, *Standard methods for the examination of water and wastewater (21st edition),* American Public Health Association, Washington, DC.

ASTM, 2010, Method D7069-04 (reapproved 2010), *Standard guide for field quality assurance in a ground-water sampling event*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2010, Method D6911-03 (reapproved 2010), *Standard guide for packaging and shipping environmental samples for laboratory analysis*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6517-00 (reapproved 2005), *Standard guide for field preservation of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), *Standard guide for field filtration of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), *Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D513-02, *Standard test methods for total and dissolved carbon dioxide in water*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D6771-02, *Standard guide for low-flow purging and sampling for wells and devices used for ground-water quality investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

Gibb, J.P., R.M. Schuller, and R.A. Griffin, 1981, *Procedures for the collection of representative water quality data from monitoring wells,* Illinois State Geological Survey Cooperative Groundwater Report 7, Champaign, IL, 61 p.

Larson, D.R., B.L. Herzog and T.H. Larson, 2003. *Groundwater geology of DeWitt, Piatt, and Northern Macon Counties, Illinois.* Illinois State Geological Survey Environmental Geology 155, 35 p.

O'Dell, J. W., J. D. Pfaff, M. E. Gales, and G. D. McKee, 1984, *Test Method- The Determination of Inorganic Anions in Water by Ion Chromatography-Method 300*, U.S. Environmental Protection Agency, EPA-600/4-84-017.

Orion Research Inc., 1990, *CO_2 Electrode Instruction Manual*, Orion Research Inc., 36 p.

Puls, R.W., and M.J. Barcelona, 1996, *Low-Flow (Minimal Drawdown) Ground-Water Sampling Procedures*. U.S. Environmental Protection Agency, EPA-540/S-95/504.

US EPA, 2009, *Statistical analysis of groundwater monitoring data at RCRA facilities – Unified Guidance*, US EPA, Office of Solid Waste, Washington, DC.

US EPA, 1974, *Methods for chemical analysis of water and wastes,* US EPA Cincinnati, OH, EPA-625-/6-74-003a.

Wood, W. W., 1976, *Guidelines for collection and field analysis of groundwater samples for selected unstable constituents*, In U.S. Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.

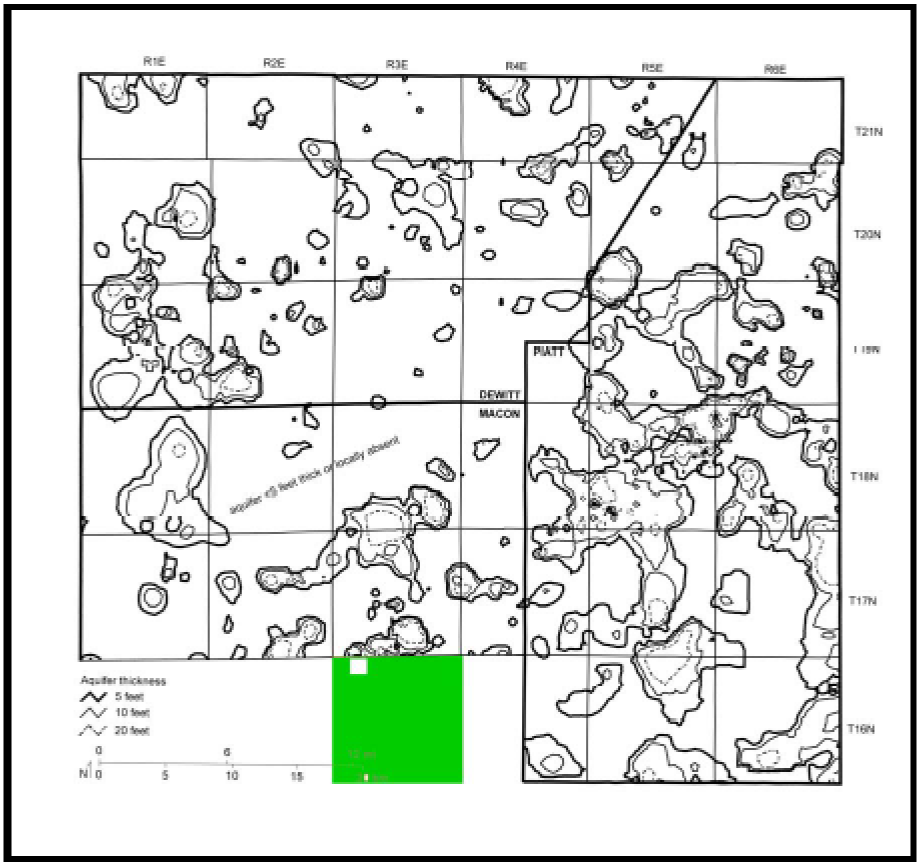


Figure 7-4. Thickness of the upper Glasford aquifer

Thickness of the upper Glasford aquifer (modified from Larson et al., 2003). The green box shows T16N, R3E. The site is located in section 5 of this township (white box within the green box). The figure shows the sporadic distribution of these sediments in Macon County.

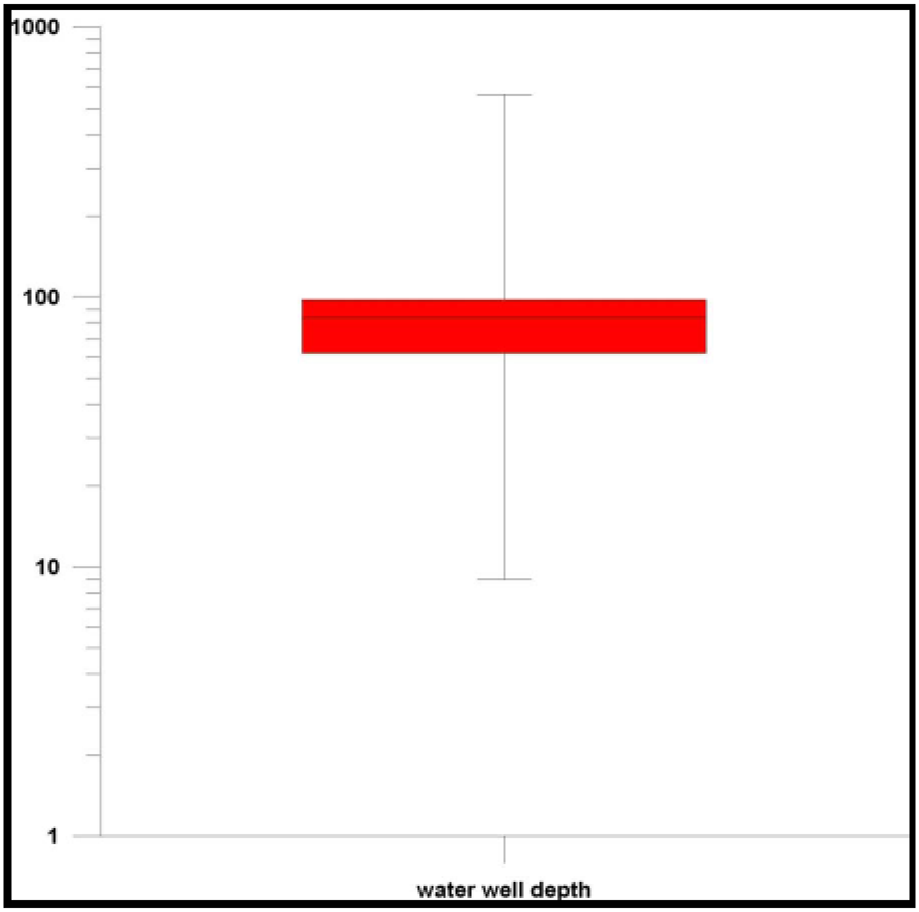


Figure 7-5. Plot of the water well depths within 2.5 miles of the injection well

The box plot shows the distribution of the well depths for 343 wells. The bottom of the box marks the 25th percentile, the middle line marks the median (50%) and the top marks the 75th percentile. The long whiskers mark the minimum and maximum.

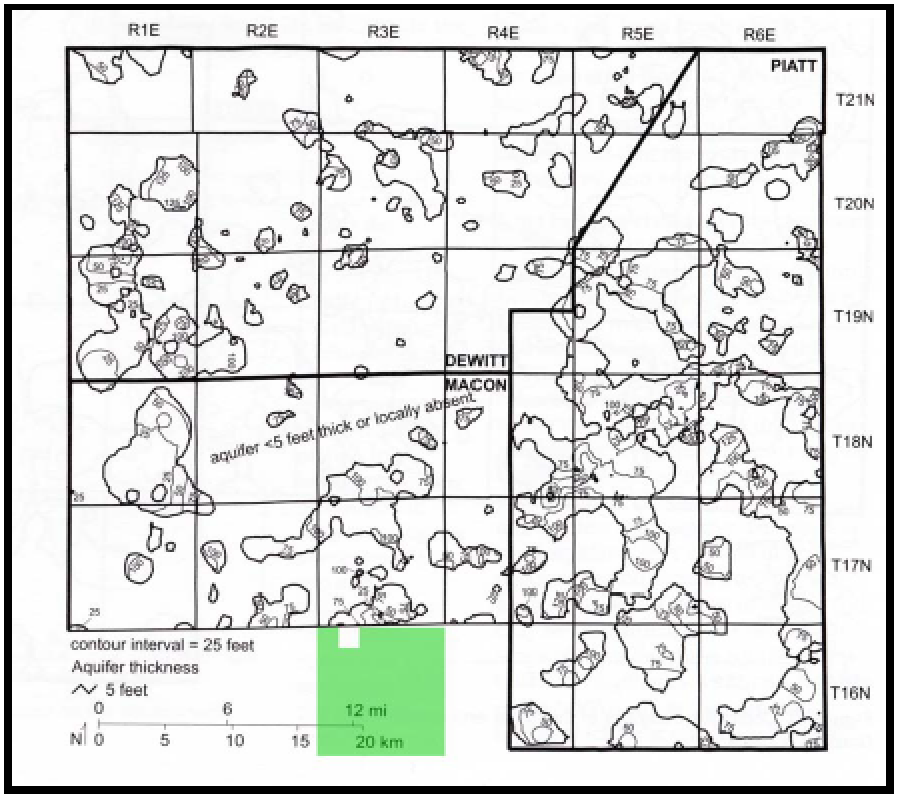


Figure 7-6. Depth to the upper Glasford aquifer

Depth to the upper Glasford aquifer (modified from Larson et al., 2003). The green box shows T16N, R3E. The site is located in section 5 of this township (white box within the green box).

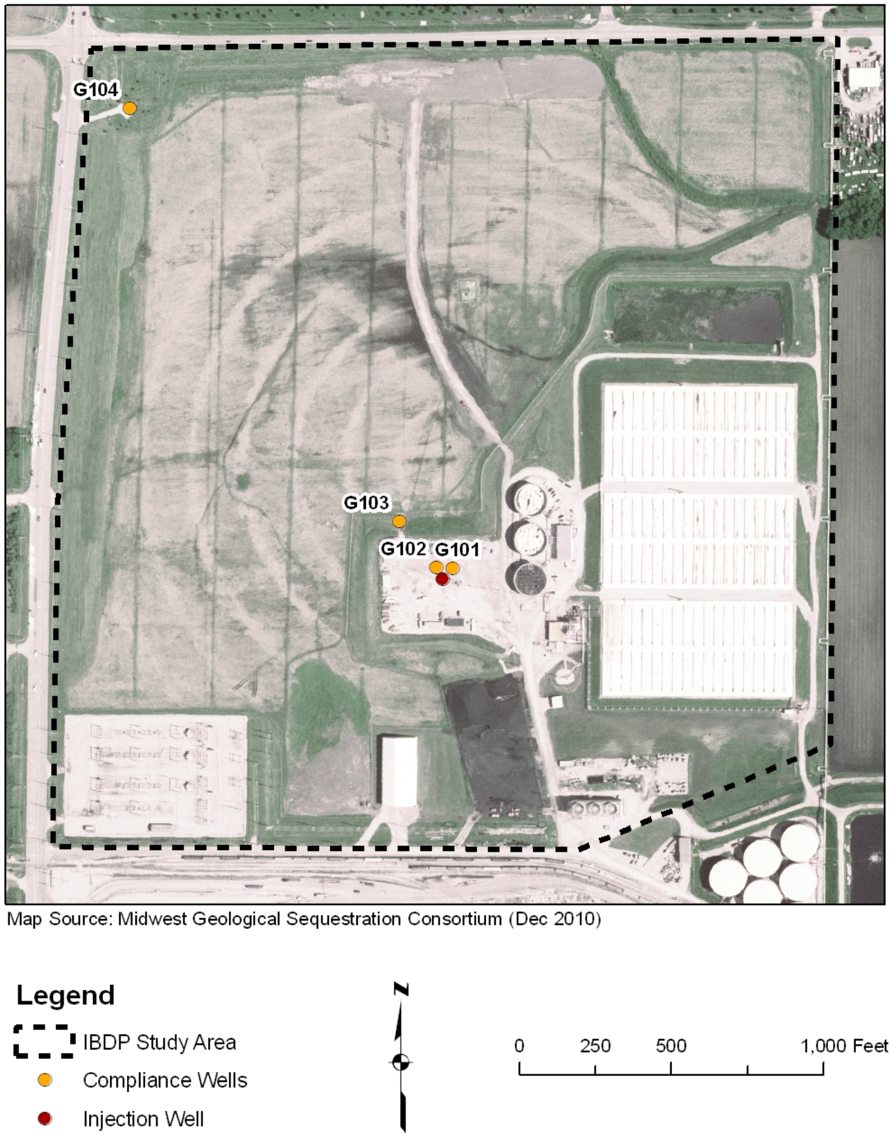


Figure 7-7. Illinois Basin – Decatur Project (IBDP) Site Map with Existing Class I Compliance Well Locations.

Illinois Environmental Protection Agency — **Well Completion Report**

Site Number: 1150155136 County: Macon

Site Name: ADM Corn Sweeteners Plant 180 Well #: G101

State Plane Coordinate: X 827089.78 Y 1169622.31 (or) Latitude: ___ o ___ ' ___ " Longitude: ___ o ___ ' ___ " Borehole #: 5/4/2010

Surveyed by: Dan Rothermel

IL Registration #: ILS 3700

Drilling Contractor: Illinois State Geological Survey

Driller: Jack Aud

Consulting Firm: Illinois State Geological Survey

Geologist: Edward Mehnert & Bracken Wimmer

Drilling Method: Wireline coring

Drilling Fluid (Type): water

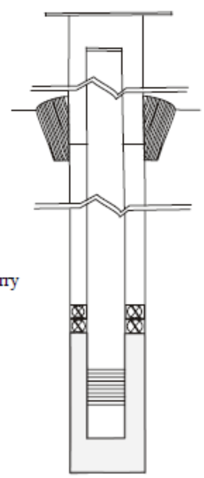
Logged By: Edward Mehnert & Bracken Wimmer

Date Started: 5/4/2010 Date Finished: 5/5/2010

Report Form Completed By: Edward Mehnert

Date: August 13, 2010

ANNULAR SPACE DETAILS



Type of Surface Seal: concrete

Type of Annular Sealant: bentonite slurry

Installation Method: tremie pipe

Setting Time: 24 hours

Type of Bentonite Seal - - Granular, Pellet, Slurry (Choose One)

Installation Method: tremie pipe

Setting Time: 24 hours

Type of Sand Pack: silica sand

Grain Size: 0.055" (Sieve Size)

Installation Method: dropped

Type of Backfill Material: bentonite pellets (if applicable)

Installation Method: dropped

Elevations (MSL)*	Depths (BGS)	(.01ft.)
676.09	2.9	Top of Protective Casing
675.59	2.4	Top of Riser Pipe
673.19	0	Ground Surface
671.59	4.0	Top of Annular Sealant
616.09	59.5	Static Water Level (After Completion)
552.29	123.3	Top of Seal
547.99	127.6	Top of Sand Pack
544.49	131.1	Top of Screen
534.49	141.1	Bottom of Screen
533.99	141.6	Bottom of Well
533.69	141.9	Bottom of Borehole

* Referenced to a National Geodetic Datum

CASING MEASURMENTS

Diameter of Borehole (inches)	6.0
ID of Riser Pipe (inches)	2.0
Protective Casing Length (feet)	5.0
Riser Pipe Length (feet)	133.7
Bottom of Screen to End Cap (feet)	0.5
Screen Length (1st slot to last slot) (feet)	10.0
Total Length of Casing (feet)	144.2
Screen Slot Size **	10

**Hand-Slotted Well Screens are Unacceptable

WELL CONSTRUCTION MATERIAL
(Choose one type of material for each area)

Protective Casing	SS304, SS316, PTFE, PVC, or Other
Riser Pipe Above W.T.	SS304, SS316, PTFE, PVC, or Other
Riser Pipe Below W.T.	SS304, SS316, PTFE, PVC, or Other
Screen	SS304, SS316, PTFE, PVC, or Other

Well Completion Form (revised 02/06/02)

Figure 7-4. Example of USDW Monitoring Well Construction Details. This completion report is for Well G101, one of the four existing regulatory compliance wells currently monitored.

8. WELL PLUGGING PLAN

8.1 INJECTION WELL PLUGGING AND ABANDONMENT

After injection has ceased the well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected down the tubing while being careful not to exceed fracturing pressure. Detailed plugging procedure will follow below.

Casing: All casing used in this well has been cemented to surface and will not be retrievable at abandonment after injection.

Tubing and Packer: After injection, the injection tubing and packer will be the only injection equipment in the cased hole. Every attempt will be made to remove the injection tubing and packer. If the packer cannot be released and removed from the cased hole, an electric line with tubing cutter will be used to cutoff the tubing above the single packer.

Plug Placement Method: The Balanced Plug placement method (Figure 1) will be used. This is a basic plug spotting process that is generally considered more efficient and considered compliant with accepted industry practices.

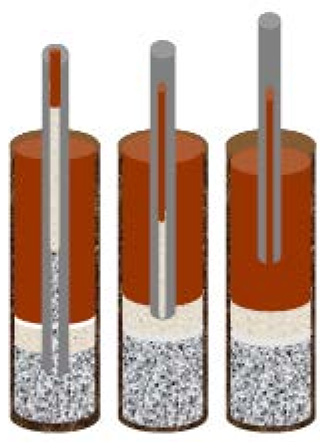


Figure 8 - 1 Schematic of pumping the cement job using the balanced plug method.
The mottled grey is cement, the white is spacer, and the brown is mud. In the first graphic, the first spacer has already been pumped, and they are pumping in the cement. In the 2nd graphic, they have displaced most of the cement (don't want to contaminate the cement, so leave a little in pipe at this stage), pulled the end of the pipe up into the space, and are displacing the end of the cement and putting more spacer fluid in between the mud and the cement. In the 3rd graphic, they are circulating mud to clean the pipe and casing of any cement before it sets.

8.1.1 *Type and quantity of plugging materials, depth intervals*

In addition to the proper volumes, placement of plugs on depths approved by the agency (the minimum requirements), all cement will be previously tested in the lab, a CemCADE* cementing design and evaluation software will be run using actual well information such as actual depth, temperature on bottom, hole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug.

All casing will be cemented to surface and no casing will be retrieved. From the surface, at least 3 feet of all the casing strings will be cutoff well below the plow line and a blanking plate with the required permit information will be welded to the top of the cutoff casing.

Detailed plugging and abandonment procedures

Notifications, Permits, and Inspections (Prior to Workover or Rig Movement)

Notifications, Permits, and Inspections are the same for plug and abandonment during construction and post-injection.

1) 1 Notify the regulatory agency at least 60 days prior to commencing operations. Insure proper notifications have been given to all regulatory agencies for rig move.
2) Ensure that the following steps are performed prior to well plugging:
    a. The injection well is flushed with a buffer fluid;
    b. The bottomhole reservoir pressure is measured;
    c. A final external mechanical integrity test is completed.
    d. Pluuging procedure has been reviewed and agreed upon by regulatory agency
3) Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and ADM have written permission to proceed with planned ultimate P&A procedure.
4) Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.
5) Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.
6) Make sure partners (U.S. DOE, IEPA and ADM) approvals have been obtained, as applicable.
7) Make sure all necessary forms for Schlumberger paperwork are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.
8) Make sure all operations have been planned and are carried out in such a manner that meets appropriate standards.

Table 8 - 1 Plugging & Abandonment Contact List

Name	Department/ Position	Office	Pager	Mobile	Home
Scott Marsteller .	Schlumberger / Operations				
Tom Stone	ADM / Project Engineer	217-424-5897			
Mark Carroll	ADM / Environmental Coordinator	217-451-2720			
Kevin Lesko	Illinois EPA	217-524-3271		217-524-3291	
Jeff McDonald	USEPA Region 5	312-353-6288			

8.1.2 *Volume Calculations*

Volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1) Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2) Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

Note: For each cementing operation the Schlumberger cementer and the wellsite supervisor will verify via the cementing handbook all calculations and have the Project Manager approve the manner and procedure for said cementing operations.

Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

8.1.3 *Plugging and Abandonment Procedure for "After Injection" Scenario:*

1. Mobilize workover (WO) or Plugging Rig Equipment. Give regulatory agency at least 60 days notice before commencing operations.

2. Move Rig # to 1st location (injection well). Notify the Project Coordinator before moving rig. Ensure all overhead restrictions (telephone, power lines, etc) have been adequately previewed and managed prior to move in and rig up (MI & RU). All CO_2 pipelines will be marked and noted to WO rig supervisor prior to moving in (MI) rig. Move rig onto location per operational procedures.

3. Conduct a safety meeting for the entire crew prior to operations, record date and time of all safety meetings and maintain records on location for review.

4. Make daily "Project Inspection" walks around the rig. Immediately correct deficiencies and report deficiencies during the regulatory discussion during morning meetings/calls. Maintain International Association of Drilling Contractors (IADC) or plugging reports daily at the WO rig log book or doghouse.

5. MI rig package and finish rigging up hoses, hydraulic lines, etc.

6. Open up all valves on the vertical run of the tree. Check pressures.

7. Rig up pump and line and test same to 2,500 psi. Fill casing with kill weight brine (9.5 ppg). Bleeding off occasionally may be necessary to remove all air from the system. Keep track and record volume of fluid to fill annulus (Hole should be full). Test casing anjnulus to 1000 psi to ensure mechanical integrity remains If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.

8. If needed, if well is not dead nor pressure cannot be bled off of tubing, rig up slickline and set plug in upper X nipple. NU BOP's and function test same. BOP's should have 4 ½"single pipe rams on top and blind rams in the bottom ram for 4 ½" Test BOP's as per local, state or federal provisions or utilize higher standard, 30 CFR250.616. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TIW's, IBOP's choke and kill lines, choke manifold, etc. to 250 psi low and 3,000 psi high. **NOTE: Make sure casing valve is open during all BOP tests.** After testing BOPs pick up 4 ½ tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Circulate well with kill weight fluid intil dead. Rig to pump via lubricator and keep well dead.

9. RU 4 ½" rig hydraulic tubing tongs for handling of production tubing. Pick back up on tubing string and pull seal assembly from seal bore. Pull hanger to floor and remove same. Circulate bottoms up with packer fluid.

10. POOH with tubing laying down same. NOTE: Ensure well does not flow due to CO2 "back flow"! Well condition is to be over-balanced at all times with at least 2 well control barriers in place at all times.

Contingency: If unable to pull seal assembly RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. Several different sizes of cutters and pipe recovery tools should be on location due to possible tight spots in tubing.

11. If successful pulling seal assembly then pick up 3 ½ or 4 ½ inch workstring and TIH with Quantum packer retrieving tools. If tubing was cut in previous step then skip this step. Latch onto Quantum packer and pull out of hole laying down same. If unable to pull Quantum pull work string out of hole and proceed to next step. Assuming tubing can be pulled with packer with no issues, run CBL, casing caliper,and/ or USIT to determine that there is no leakage around the wellbore above the caprock. If leakage is noted prepare cement remediation plan and execute during plugging operations. Remediation plan will be submitted tp regulating agency and no work will beging until regulating agency approves mitigation plan. Trip in hole with work string to TD. Keep hole full at all times. Circulate well and prepare cement plugging operations.
12. Lower section of the well will be plugged using CO2 resistant cement from TD at +/- 7000ft to 1000ft above the top of the Eau Claire formation approximately 4000 ft. This will be accomplished of spotting plugs in 500 ft increments. Using a density of 15.9ppg slurry with a yield of 1.11cu.ft/sk a total of approximately 1150 sacks of cement will be required. Actual cement volume will depend upon actual weight of the casing within the plugged zone. This will require at least six plugs of 500 feet in length. NO more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug
13. After well is plugged back to 4000 ft ccirculate well a 9.4 ppg drilling mud. Plugging above 4000 ft will be done at the regulating agency's discretion bit at a minimujm of a 500 ft plug at surface comprised of neat Class A/H cement.(Density 15.8 ppg, yield 1.18 cu ft/sk). If well is to be plugged continuousily to surface then proceed to step 14.

14. Circ well and ensure well is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 175 sacks Class A or H). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 8 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. The following morning trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. Calculate volume for final plug. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug. Total of approximately 1500 sacks total cement used in all remaining plug above 4000ft.. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 ft. or as per regulating agency directive.

15. Complete plugging forms and send in with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and shall be submitted within 60 days after plugging is completed.

Note: Utilize all local, state or federal rules relative to P&A or at least 33% plus actual volumes or as approved previously by the permitting agency.

Table 8 - 2 Cost estimate for plugging and abandonment worst case scenario

Itemized P&A Costs	**Post Construction+**
a. Casing Evaluation: Mobilize equipment and crews from nearest district. Run multi-finger caliper for detailed inspection of the inner surface of the casing. Run Isolation Scanner for final condition of outer surface of casing and cement condition. Compare to baseline logs run before injection started.	$50,000
b. Evaluation of any problems discovered by the casing evaluation: Downhole video camera to get visual images of the questionable inner surfaces of the casing.	$20,000
c. Cost for repairing problems and cleanup of any groundwater or soil contamination: CO_2 as a vapor in soil would not result in contamination like a liquid. A formal "cleanup" may not be required, and the CO_2 would dissipate into the atmosphere. CO_2 into groundwater would like be the same as that in oil. For a period of time, the shallow groundwater may have a low concentration of CO_2 similar to a "flat" soft drink. With time the CO_2 will dissipate into the unsaturated soil and dissipate.	$40,000
d. Cost for cementing or other materials used to plug the well:	$78,000
e. Cost for labor, engineering, rig time, equipment and consultants:	$157,000
f. Cost for decontamination of equipment:	N/A
g. Cost for disposal of any equipment: Tubing would be sold as scrap metal and worst case cost would be trucking services only.	$2,000
h. Estimated sales tax: Our review shows there is no state sales tax for this kind of work.	$2,000
i. Miscellaneous and minor contingencies (20%):	$10,000
j. Total	$359,000

+ Post Construction cost is for 1/1/08; if the well was abandoned 30 years from now, assuming 3% annual inflation the worst case P&A would be 2.43 times greater or $873,370.

8.2 **VERIFICATION WELL**

Abandonment after construction

Removal of subsurface well features

Casing: All casing used in this well has been cemented to surface and will not be retrievable at abandonment after injection.

Tubing and Packers: The Westbay packers will be deflated and the tubing string removed. If the packers cannot be released and removed from the cased hole, a determination will be made as to where in the well the pipe is stuck and an electric line with tubing cutter will be used to cutoff the tubing above the lowest stuck packer.

Plug Placement Method: The Balanced Plug placement method will be used. This is a basic plug spotting process that is generally considered more efficient and is consistent with best industry practices.

8.2.1 Type and quantity of plugging materials, depth intervals

In addition to the proper volumes, placement of plugs on depths approved by the permits (the minimum requirements), all cement will be previously tested in the lab, a CemCADE* cementing design and evaluation software will be run using actual well information such as actual depth, temperature on bottom, hole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug. All casing is cemented to surface and no casing will be retrieved. From the surface, at least 3 feet of all the casing strings will be cutoff well below the plow line and a blanking plate with the required permit information will be welded to the top of the cutoff casing.

8.2.2 *Detailed plugging and abandonment procedures*

Notifications, Permits, and Inspections (Prior to Workover or Rig Movement) Notifications, Permits, and Inspections are the same for plug and abandonment during construction and post-injection.

1. Notify EPA 48 hours prior to commencing operations. Insure proper notifications have been given to all regulatory agencies for rig move.

2. Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and ADM has written permission to proceed with planned ultimate P&A procedure.

3. Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks, and ancillary equipment to perform

P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.

4. Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.

5. Make sure all operations have been planned and are carried out in such a manner that meets appropriate standards.

8.2.3 *Volume Calculations*

Estimated volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1. Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2. Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

3. See generic calculations in Figure 2. Have cementer and wellsite supervisor both review calculations prior to spotting any plug.

Note: For each cementing operation the cementer and the wellsite supervisor will verify via a cementing handbook or iHandbook all calculations and have ADM approve the manner and procedure for cementing operations. Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

8.2.4 *Possible Plugging and Abandonment Procedure*

At the end of the serviceable life of the verification well, the well will be plugged and abandoned.

In summary, the plugging procedure will consist of removing all components of the completion system and then spotting cement plugs along the entire length of the well. At the surface the well head will be removed and casing cut off 3 feet below surface. A detailed procedure follows:

1. Move in workover unit with pump and tank.

2. Fill both tubing and annulus with kill weight brine.

3. Nipple down well head and nipple up BOPs

4. Remove all downhole equipment from well

5. Keep hole full with workover brine of sufficient density to maintain well control

6. Pick up 2 7/8” tbg work string (or comparable) and trip in hole to PBTD

7. Circulate hole two revolutions to ensure that uniform density fluid is in the well

8. Start setting cement plugs by spotting 56 sacks Class A cement with 1% TIC. This amount is equal to 500 ft in the 5 ½” casing. Pull 10 stands (20 joints) tbg and reverse circulate hole for two tbg volumes. Lay down tubing as it is pulled from well.

9. Repeat plug setting procedure until uppermost set of perforations is covered. Reverse circulate hole one revolution.

10. Pull ten stands and shut down overnight.

11. On the next morning TIH ten stands and tag plug. Resume plugging procedure as before and continue spotting plugs until the last plug at the surface. Repeat until last plug at surface and spot the appropriate volume of cement to reach surface.

12. Nipple down BOPs

13. Cut off all well head components and cut off all casings at below ground level.

14. Finish filling well with cement.

15. Install permanent marker back to surface on which all pertinent well information is inscribed.

16. Fill cellar with topsoil.

17. Rig down workover unit and move out all equipment. Haul off all workover fluids to proper disposal site.

18. Reclaim surface to normal grade and reseed location.

7,500 ft 5 ½” 15.5 #/ft casing requires 850 sks cement to fill, 25 plugs (estimated)
Approximately five days required from move in to move out, depending on the operations at hand and the physical constraints of the well, weather, etc..

Table 8 - 3 Cost estimate for plugging and abandonment worst case scenario

Itemized P&A Costs	**Post Construction**[+]
a. Casing Evaluation: Mobilize equipment and crews from nearest district. Run multi-finger caliper for detailed inspection of the inner surface of the casing. Run Isolation Scanner for final condition of outer surface of casing and cement condition. Compare to baseline logs run before injection started.	$50,000
b. Evaluation of any problems discovered by the casing evaluation: Downhole video camera to get visual images of the questionable inner surfaces of the casing.	$20,000
c. Cost for repairing problems and cleanup of any groundwater or soil contamination: CO_2 as a vapor in soil would not result in contamination like a liquid. A formal “cleanup” may not be required, and the CO_2 would dissipate into the atmosphere. CO_2 into groundwater would like be the same as that in oil. For a period of time, the shallow groundwater may have a low concentration of CO_2 similar to a “flat” soft drink. With time the CO_2 will dissipate into the unsaturated soil and dissipate.	$40,000
d. Cost for cementing or other materials used to plug the well:	$37,000
e. Cost for labor, engineering, rig time, equipment and consultants:	$157,000
f. Cost for decontamination of equipment:	N/A
g. Cost for disposal of any equipment: Tubing would be sold as scrap metal and worst case cost would be trucking services only.	$2,000
h. Estimated sales tax: Our review shows there is no state sales tax for this kind of work.	$2,000
i. Miscellaneous and minor contingencies (20%):	$10,000
j. Total	$318,000

[+]Post Construction cost is for 1/1/10; if the well was abandoned 30 years from now, assuming 3% annual inflation the worst case P&A would be 2.43 times greater or $772,740.

8.3 GEOPHYSICAL WELL

8.3.1 8.3.1 Well Abandonment

At the end of the serviceable life of the well, the well will be plugged and abandoned utilizing the following procedure:

1. Notify EPA of abandonment at least 24 hours prior to plugging the well.

2. Cement may be circulated from total depth or plugged-back total depth to surface or cement plugs may be placed as specified below.
    a. Cement plug circulated or dump bailed over any perforated interval (none planned).

    b. Cement plug circulated inside casing from 500' to a minimum of 250'

3. Cut off all well head components and cut off all casings below ground level.

4. Finish filling well with cement.

5. Install permanent marker at surface.

VOLUME CALCULATIONS

1. CAPACITIES

Determine the following capacities:

Annular capacity between drillpipe and hole (V_{ANN})	ft^3/ft and ft/bbl
Hole or casing capacity (V_{CAPOH})	ft^3/ft
Drillpipe or tubing capacity (V_{CAPDP})	ft^3/ft and bbl/ft

2. NUMBER OF SACKS OF CEMENT

Determine the number of sacks of cement required for a given length of plug (sx):

$N_{SX} = L_{PLUG} \times V_{CAPOH}$ / slurry yield

Where:

N_{SX} = number of sacks of cement, sx

L_{PLUG} = length of cement plug, ft

V_{CAPOH} = capacity of open hole or casing, ft^3/ft

Slurry yield = cement yield, ft^3/sk

3. SPACER VOLUME BEHIND SLURRY

Determine the spacer volume to be pumped behind the slurry to balance the plug (bbls):

$V_{TAILSPACER} = V_{ANN} \times V_{LEADSPCR} \times V_{CAPDP}$

Where:

$V_{TAILSPACER}$ = spacer volume to be pumped behind the slurry to balance the plug, bbls

V_{ANN} = annular capacity, ft/bbl

$V_{LEADSPCR}$ = spacer volume to be pumped ahead of cement plug, bbls

V_{CAPDP} = drill pipe capacity, bbl/ft

Figure 8 - 2 Sample Plugging Calculations

VOLUME CALCULATIONS, CONTINUED

4. PLUG LENGTH

Determine the plug length (ft) before the drill pipe is withdrawn (ft):

L_{PLUG} = (N_{SX} X slurry yield) / (V_{ANN} + V_{CAPDP})

Where:

L_{PLUG} = length of cement plug before the DP is withdrawn, ft

N_{SX} = number of sacks of cement, sx

Slurry yield = cement yield, ft^3/sk

V_{ANN} = annular capacity, ft^3/ft

V_{CAPDP} = drill pipe capacity, ft^3/ft

5. LENGTH OF FREEFALL IN DRILL PIPE

Determine the length of mud free fall in drill pipe (ft):

L_{FF} = TD (1 – MW)

Where:

L_{FF} = length of free fall inside the drill pipe, ft

TD = depth, ft

MW = mud density, pPG

6. DISPLACEMENT VOLUME

Determine displacement volume required to spot the plug (bbl):

V_{DISP} = [(L_{DP} – L_{PLUG} – L_{FF}) X V_{CAPDP}] – $V_{TAILSPCR}$

Where:

V_{DISP} = displacement volume required to spot cement plug, bbls

L_{DP} = length of drill pipe, ft

L_{PLUG} = length of cement plug, ft

L_{FF} = length of freefall, ft

V_{CAPDP} = drill pipe capacity, bbl/ft

$V_{TAILSPCR}$ = spacer volume to be pumped behind the slurry to balance the plug, bbls

Figure 8 - 3 Continued Sample Plugging Calculations

9. POST-INJECTION SITE CARE AND SITE CLOSURE

9.1 DESCRIPTION OF POST-INJECTION SITE CARE AND CLOSURE

Postinjection site care and closure (PISC) will meet the requirements of 40 CFR 146.93. Upon the cessation of injection, the site model will be updated with the most recent monitoring data and reviewed with respect to the final PISC plan. If no changes to the PISC plan are warranted a report detailing these results, that no changes will be required, will be submitted to the Director. If changes to the PISC plan are necessary, an amended PISC plan will be submitted to the Director for approval and incorporation into the permit subject to the permit modification requirements at §§ 144.39 or 144.41.

The default PISC period is 50 years, however, for this project a 10-year period is being requested. The modified PISC period is based on current modeling and characterization data that show that the sequestered CO_2 will no longer pose an endangerment to USDWs and will meet the requirements for an alternative PISC period as detailed in § 146.93(c)(1) and (2).

9.1.1 Description of Post-injection Monitoring

During the PISC period the site monitoring and modeling will continue.. The site monitoring program will be a continuation of the operational monitoring, verification, and accounting (MVA) program. Table 9-1 details MVA activities during the site's pre-injection, injection, and postinjection periods. In Table 9-2 the post-injection monitoring schedule is presented. The monitoring during the PISC period will include seismic surveys, well based pressure measurements, and sample analysis. The following paragraphs detail the post-injection monitoring techniques to be employed in this program:

1) Seismic survey: in order to define the location and extent of the CO_2 plume, seismic surveys will be designed, acquired, and interpreted for the area of review (AoR) upon completion of the injection period and during the PISC period. The optimum survey lines for the post-closure seismic surveys will be determined using up-to-date site-specific seismic data and updated reservoir model results. The surveys will be used to validate the site models, determine the position and extent of the CO_2 plume, and verify that the CO_2 will not pose an endangerment to USDWs. Further need for seismic surveying and extension of the PISC period will be evaluated based on the measured extent of the plume, the plume's rate of expansion, correlation with site modeling results, and potential risk of endangerment to USDWs.

2) Shallow groundwater monitoring: samples will be taken from the shallow groundwater monitoring wells required by permit. The schedule for monitoring will be quarterly in year one (1) and annually thereafter. The groundwater monitoring program will follow the plan defined in Section 7.3 - Groundwater Monitoring.

3) Injection well monitoring: during PISC period the injection well will be used to monitor the pressure and temperature at the injection zone (packer).

4) Verification well monitoring: The verification well will be used to monitor the pressure and temperature at the monitoring ports within and above the Mt. Simon Sandstone.

Because the PISC monitoring is a continuation of the operational monitoring, there will be no modification in the well monitoring plan and sample locations. Figure 9-1 shows the locations of the PISC monitoring wells.

During the PISC period, additional seismic and well-based monitoring data will be collected and analyzed. The new data will be used to update and validate the site models for both fate and transport of CO2 and the location of the pressure front. The PISC data will also aid in calculating and monitor the pressure differential between the pre- and post-injection periods in the injection zone, as required by § 146.93(a)(2)(i).

Table 9 - 1 Summary of Monitoring, Verification and Accounting Activities

Monitoring Activity Description	Monitoring Period		
	Pre-CO2 Injection	During Injection	Post Injection
Seismic Survey (will not extend over the entire PISC period)	X	X	X
Shallow groundwater regulatory compliance wells - water quality	X	X	X
Injection Well Monitoring - injection volumes		X	
Injection Well Monitoring - injection well surface pressure	X	X	X
Injection Well Monitoring - annulus pressure	X	X	X
Verification Well Monitoring - injection formation pressure	X	X	X
Verification Well Monitoring - injection formation temperature	X	X	X
Geophysical Well Monitoring – Vertical Seismic Profiling	X	X	
Injection and Verification Wells – downhole CO_2 detection e.g. RST surveys	X	X	X

Table 9 - 2 Summary of Post-Injection Monitoring Schedule

Monitoring Activity Description	Schedule
Seismic Survey	following cessation of injection
Shallow groundwater regulatory compliance wells - water quality	Quarterly (Year 1) & Annually (Year 2+)
Injection Well Monitoring - injection well tubing head pressure	Annually
Injection Well Monitoring - annulus pressure	Continuous
Verification Well Monitoring - injection formation pressure	Continuous
Verification Well Monitoring - injection formation temperature	Continuous
Injection and Verification Wells– RST Surveys	Post Injection Years 1, 4, 9 (this schedule may change with updates of the PISC plan during or after injection)

9.1.2 *Schedule for Submitting Post-injection Site Care Monitoring Results*

Post-injection site care monitoring data and modeling results will be submitted to the EPA in an annual report. The report will be submitted in an electronic format approved by the EPA. The annual reports will contain information and data generated during the reporting period including: seismic data, well-based monitoring data, sample analysis, and updated site model results.

9.1.3 *Post-injection Site Care Timeframe*

The default timeframe for post-injection site care is fifty years; however, the operator is seeking an alternate timeframe based on consideration and documentation of site-specific conditions that satisfy the requirements listed in the Code of Federal Regulations section (CFR) § 146.93(c)(1). These site specific conditions are described in the following paragraphs.

- CFR Section §146.93(c)(1)(i) states that “The results of computational modeling performed pursuant to delineation of the area of review under § 146.84” needs to be considered. The results of computational modeling of the project (Section 6 of this application) indicate that the sequestered CO_2 will not migrate above the Mt. Simon Sandstone.
- CFR Section §146.93(c)(1)(ii) “The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures” also needs to be considered. The formation pressure at the injection zone is predicted to decline rapidly within the first 4 years following injection. The

formation pressures will increase from a pre-injection pressure 2,840 psia to 3,340 psia immediately following injection dropping to 2,950 psia after four years post-injection. Additionally fifty years post-injection, the formation pressure is predicted to be 2,860 psia. The increase in the injection formation pressure at the edge of the AoR is expected to be 184 psi at the cessation of injection and less than 110 psi within 4 years. By 8 years the pressure increase due to the injection has dropped below 184 psi everywhere on the site and the AOR is just defined by the CO2 boundary.

- CFR Section §146.93(c)(1)(vii) also suggests weight be given to "A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-frac*tures* and of appropriate thickness, permeability, and integrity to impede fluid (*e.g.,* carbon dioxide, formation fluids) movement". The hydrogeologic and seismic characterization for the project site indicates that the Eau Claire Formation, the primary seal above the Mt. Simon, does not contain any faults and has permeability sufficiently low to impede CO_2 migration to overlying formations.
- "The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure" , CFR Section §146.93(c)(1)(viii) is also important. Potential conduits of CO_2 migration above the Mt. Simon are limited to the IBDP injection and verification wells or the IL-ICCS injection and verification wells, all of which have been/will be constructed, monitored, and plugged in a manner that will minimize the potential for any such migration and will meet the requirements of 40 CFR Part 146.
- The last consideration for a 10-year PISC period is based on §146.93(c)(1)(x), "The distance between the injection zone and the nearest USDWs above and/or below the injection zone" at the site the Mt. Simon injection zone is nearly 7,000 feet below the lowermost USDW, and there are three confining formations (New Albany Shale, Maquoketa Formation, Eau Claire Formation) between the injection zone and the lowermost USDW making it very unlikely that CO_2 would ever reach a USDW.

9.1.4 *Site Closure*

The operator will notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, all remaining monitoring wells will be plugged and abandoned in accordance with the methods described in Section 8. A site closure report will be prepared within 90 days following site closure, documenting the following:

- plugging of the injection, verification, and geophysical wells,
- location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,

- notifications to state and local authorities,
- records regarding the nature, composition, and volume of the injected CO_2
- post-injection monitoring records.

Notation to the property's deed on which the injection well was located shall indicate the following:

- property was used for carbon dioxide sequestration,
- name of the local agency to which a plat of survey with injection well location was submitted,
- the volume of fluid injected,
- the formation into which the fluid was injected, and
- the period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the operator for a period of 10 years following site closure. Additionally, the operator will maintain the records collected during the PISC period for a period of 10 years after which these records will be delivered to the Director.

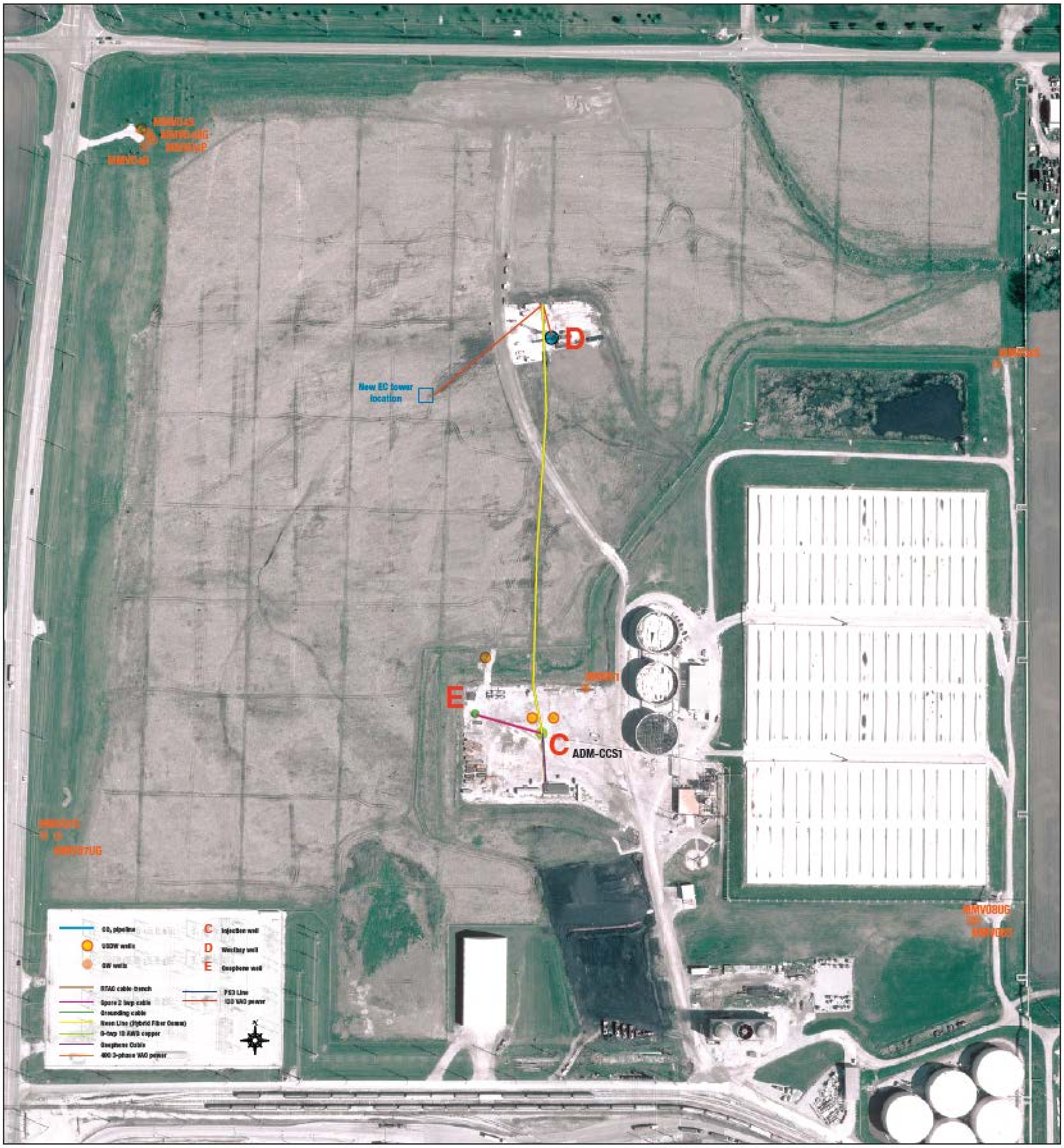


Figure 9 - 1 Location information for wells and other facilities.

10. EMERGENCY AND REMEDIAL RESPONSE, AND CONTINGENCY PLANS

10.1 EMERGENCY AND REMEDIAL RESPONSE PLAN

This emergency and remedial response plan (ERRP) describe actions that the owner / operator (ADM) may take to address movement of the injection fluid or formation fluid in a manner that may endanger USDWs during operation or post-injection periods. Steps to prevent unexpected CO_2 movement have already been implemented in response to site risk assessment and risk analysis. This plan describes actions to be taken if the unexpected movement occurs.

Facility Name:	Archer Daniels Midland Company (ADM) Illinois Basin - Decatur Project
Facility Contacts:	A site-specific list of facility contacts will be developed and maintained during the life of the project.
Injection Well Location:	The well is located on the surface 438 feet South and 1332 feet East in the Northwest quadrant of Section 5 of Township 16 North and Range 3 East

If ADM obtains evidence that the injected carbon dioxide (CO_2) stream and/or associated pressure front may endanger a USDW, ADM will perform the following actions:

1. Immediately shut down the injection well.
2. Take all steps reasonably necessary to identify and characterize the potential release.
3. Notify the permitting agency (UIC Program Director) of the event within 24 hours.
4. Implement the remedial response.

10.1.1 Local Resources and Infrastructure

Resources in the vicinity of the IBDP project that may be impacted as a result of an emergency at the project site include: USDWs, potable water wells, the Sangamon River, Bois Du Sangamon Nature Preserve, and Lake Decatur. Infrastructure in the vicinity of the IBDP project that may be impacted as a result of an emergency at the project site includes: Richland Community College, Heartland Community Church, various residential areas, commercial properties, and recreational facilities; and ADM corn processing facilities. A map of the local area is provided as Figure H-1 at the end of this plan.

10.1.2 Potential Risk Scenarios

The following events related to the IBDP could potentially call for emergency response, including:

- Injection or verification well integrity failure
- Injection well monitoring equipment failure
- A natural disaster with effects that could impact IBDP operations
- Brine leakage to a USDW
- Carbon dioxide leakage to USDW or land surface

Response actions will depend on the severity of the event(s) triggering an emergency response. Emergency events will be categorized as major, serious, and minor emergencies (Table 10-1).

Table 10 - 1 Definition of Emergency Conditions

Emergency Condition	Definition
Major Emergency	Event poses immediate risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious Emergency	Event poses potential risk to human health, resources, or infrastructure if conditions worsen or no response actions are taken.
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Events that require cessation of injection will result in CO_2 being released to the atmosphere.

10.1.3 Emergency Identification and Response Actions

The process for identifying establishing the type and severity of any event will be event-specific. Likely steps for responding to the risk scenarios in Section 10.2 are detailed below. **In the event of an emergency requiring outside assistance, the project contact lead shall call the ADM Security Dispatch at (217) 424-4444.**

Well Integrity Failure

A loss of well integrity for either the Injection or Verification wells may be signaled by:

a. Automatic shutdown devices are activated. (**NOTE: The activation of an automatic shutdown device does not, in itself, constitute an emergency event.**)
    - Annulus pressure varies outside of the permitted range

b. Mechanical integrity test and log results show a potential loss of integrity.

Response Actions:

- Immediately notify the ADM and other designated project contacts.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- Notify the UIC Program Director within 24 hours of the incident, if event meets the definition of an "emergency" condition.
- For a Major or Serious Emergency:
    - Cease injection immediately.
    - Shut in well (close flow valve). Vent CO_2 from surface facilities.
    - Limit access to wellhead to authorized personnel only, as necessary.
    - Communicate with Corn Plant personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, annulus pressure.
    - Verify integrity loss and determine the cause and extent of failure.
    - Identify further remedial actions to correct any loss of integrity
- For a Minor Emergency:
    - Cease injection immediately.
    - Shut in well (close flow valve). Vent CO_2 from surface facilities.
    - Reset automatic shutdown devices.
    - Monitor well pressure, temperature, annulus pressure.
    - Verify integrity loss and determine the cause and extent of failure.
    - Identify further remedial actions to correct any loss of integrity

Injection Well Monitoring Equipment Failure.

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs or just a problem with the monitoring equipment. (**NOTE: The failure of monitoring equipment does not, in itself, constitute an emergency event.**)

Response Actions:

- Immediately notify the ADM and other designated project contacts.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- Notify the UIC Program Director within 24 hours of the incident, if event meets the definition of an "emergency" condition.
- For a Major or Serious Emergency:
    - Cease injection immediately.
    - Shut in well (close flow valve). Vent CO_2 from surface facilities.
    - Limit access to wellhead to authorized personnel only, as necessary.

- Communicate with Corn Plant personnel and local authorities to initiate evacuation plans, as necessary.
- Monitor well pressure, temperature, annulus pressure (record them manually if necessary using the field log shown in Figure 10-2).
- Determine the cause and extent of failure.
- Identify further remedial actions to correct the specific failure

- For a Minor Emergency:
  - Cease injection immediately.
  - Shut in well (close flow valve). Vent CO_2 from surface facilities.
  - Reset or repair automatic shutdown devices.
  - Monitor well pressure, temperature, annulus pressure (record them manually if necessary).
  - Determine the cause and extent of failure.
  - Identify further remedial actions to correct the specific failure

Potential CO_2 Leakage to Land Surface

Elevated concentrations of CO_2 or other evidence of CO_2 leakage to the land surface are detected.

Response Actions:

- Immediately notify the ADM and other designated project contacts.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- Notify the UIC Program Director within 24 hours of the incident, if event meets the definition of an "emergency" condition.
- For all Emergencies (Major, Serious, and Minor):
  - Cease injection immediately.
  - Shut in well (close flow valve). Vent CO_2 from surface facilities.
  - Limit access to wellhead to authorized personnel only, as necessary.
  - Communicate with Corn Plant personnel and local authorities to initiate evacuation plans, as necessary.
  - If suspected release is from the wellhead, take steps to stop the leak, and repair, if possible. If release is significant (i.e., a well "blowout"), take steps to kill well.
  - If suspected release is away from the wellhead, take steps to log well to detect CO_2 movement outside of casing or rule out the well as a leakage pathway.
  - Isolate the suspected release area with the assistance of local authorities, if necessary.

    - Use trained personnel to inspect the suspected release area and conduct CO_2 air monitoring at the suspected release point, or, if a larger area, establish a sampling grid within the suspected release area and monitor at sample grid points.
    - If a release point is not identified from the above actions, perform additional CO_2 air measurements within the sampling grid.
    - Use collected data to pinpoint the suspected release area.
    - Establish a restricted area around the release with the assistance of local authorities, if necessary.
    - Take appropriate steps to stop the CO_2 release and and reduce the CO_2 concentration in the area of release.
    - Continue monitoring within the release area until monitoring data indicate that the release has been mitigated.

Potential Brine or CO_2 Leakage to USDW

Elevated values of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW.

Response Actions:

- Immediately notify the ADM and other designated project contacts.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- Notify the UIC Program Director within 24 hours of the incident, if event meets the definition of an "emergency" condition.
- For all Emergencies (Major, Serious, or Minor):
    - Cease injection immediately.
    - Shut in well (close flow valve). Vent CO_2 from surface facilities.
    - Collect confirmation samples of groundwater and verify the initial positive measurement.
    - If the presence of CO2 or brine are confirmed, develop a case-specific work plan to
        a. install additional groundwater monitoring points near the impacted groundwater well(s) to delineate the extent of impact; and
        b. remediate impacts to the USDW.
    - If it is determined to be necessary, arrange for an alternate potable water supply, if the USDW was being utilized.
    - Proceed with efforts to remediate USDW
    - Continue groundwater remediation, monitoring on a frequent basis (frequency to be determined by ADM and the UIC Program Director) until the USDW impact has been fully addressed.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster impacting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; weather-related disasters may impact surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, perform the following:

Response Actions:

- Immediately notify the ADM and other designated project contacts.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- Notify the UIC Program Director within 24 hours of the incident, if event meets the definition of an "emergency" condition.
- For a Major or Serious Emergency:
  - Cease injection immediately.
  - Shut in well (close flow valve). Vent CO_2 from surface facilities.
  - Limit access to wellhead to authorized personnel only, as needed.
  - Communicate with Corn Plant personnel and local authorities to initiate evacuation plans, as necessary.
  - Monitor well pressure, temperature, annulus pressure to verify well status
  - Determine if there has been a failure and of so, the cause and extent of the failure.
  - Identify further remedial actions to correct the specific failure if one occurred

- For a Minor Emergency:
  - Cease injection immediately.
  - Shut in well (close flow valve). Vent CO_2 from surface facilities.
  - Limit access to wellhead to authorized personnel only.
  - Monitor well pressure, temperature, annulus pressure to verify well status
  - Determine if there has been a failure and of so, the cause and extent of the failure.
  - Identify further remedial actions to correct the specific failure if one occurred

10.1.4 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. The injection well and areas to the west and southwest are located within the limits of the City of Decatur; however, adjacent areas to the southeast, east, and north are outside of city limits. Therefore, city and county emergency responders (as well as state agencies) may need to be notified in the event of an emergency.

Site personnel:
ADM Project Engineer
ADM Corn Plant Environmental Manager
ADM Plant Manager, Plant Superintendent, or General Foreman
ADM Corporate Communications Contact

Project personnel:
Subcontractor Project Manager(s)

Local Authorities: including (but not limited to)
City of Decatur Police Department
City of Decatur Fire Department
Macon County Sheriff
Illinois State Police
Macon County Emergency Management Agency
Illinois Emergency Management Agency

The type of equipment needed in the event of an emergency and remedial response will vary, depending on the triggering event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig) is required, the designated Subcontractor Project Manager shall be responsible for its procurement.

10.1.5 Emergency Communications Plan

A site-specific emergency contact list will be developed and maintained during the life of the project.

Emergency communications with the public will be handled by ADM Corporate Communications. The individual to be designated by ADM will be the first contact during an emergency event. This individual will contact the crisis communication team as appropriate. Emergency responses to the media will be dealt with only by the personnel so designated by ADM. Those individuals should try to be reachable 24 hours a day for contact in the event of an emergency.

In the event that anyone else is contacted to comment on any situation deemed an "emergency", the media contact should be directed to the ADM-designated individual, who will oversee all media communications with the public (through either interview, press release, Web posting, or other methods) in the event of an emergency situation related to the Illinois Basin Decatur Project=.

10.1.6 Plan Review

The ERRP shall be reviewed:

- at least once every five (5) years following its approval by the permitting agency
- within one (1) year following an area of review (AOR) re-evaluation
- within a prescribed period (to be determined by the permitting agency) following any significant changes to the injection process or injection facility

If the review indicates that no amendments to the ERRP are necessary ADM will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within one (1) year following an event that initiates the ERRP review procedure.

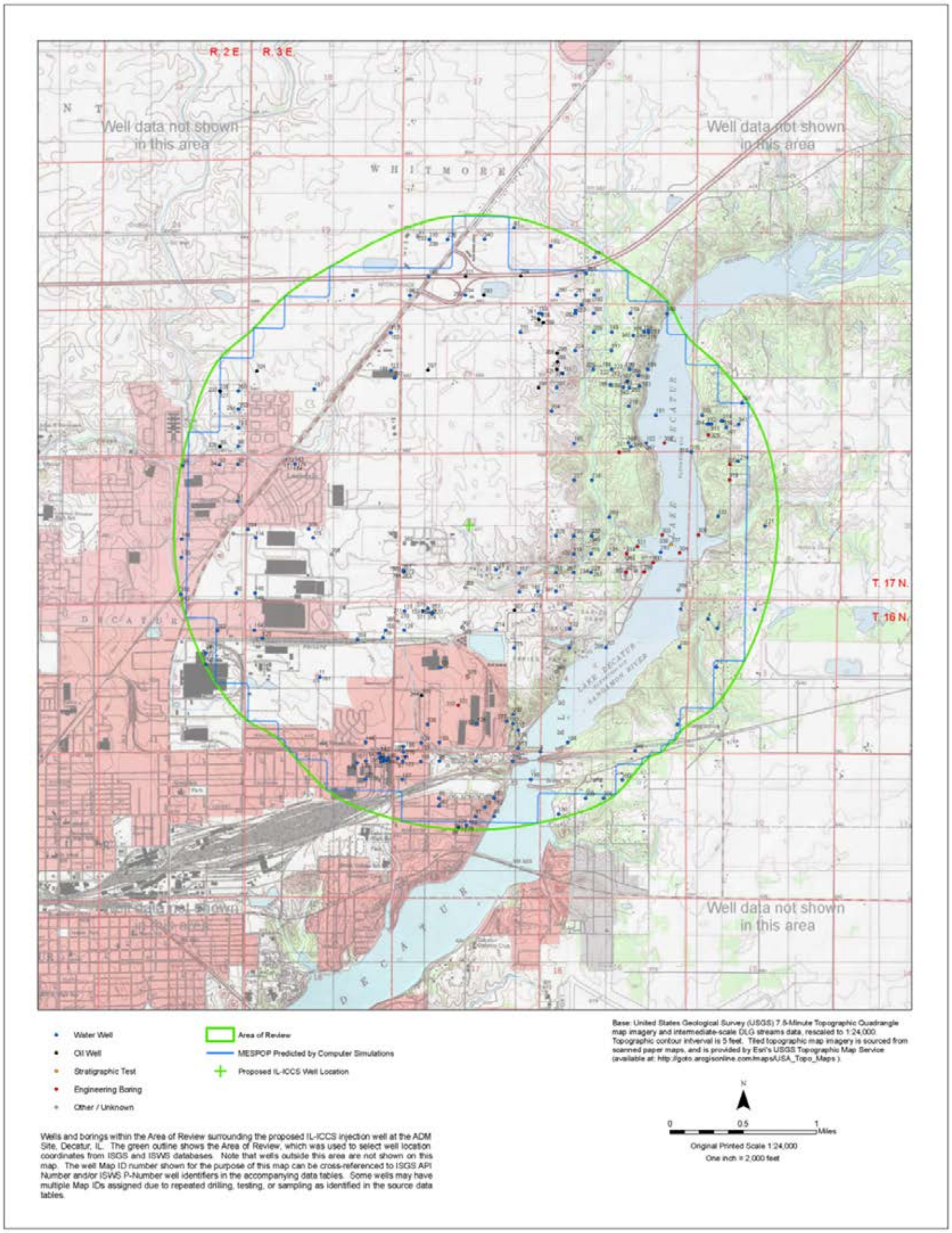


Figure 10 - 1 Local area map for the IBDP project.

Emergency & remedial response activities will most likely be within the “area of review” highlighted on the map. This map illustrates the resources and infrastructure in the vicinity of the IBDP project. ADM Corn Plant facilities are south of the injection well, Richland Community College and Heartland Community Church are to the north and norhtwest, respectively. The closest residential/commercial/industrial areas are to the east of the injection well. Lake Decatur / Sangamon River and natural / recreational areas are generally east to southeast of the injection well. Source: ISGS and ISWS well databases, current as of May 10, 2011.

FIELD LOG – INJECTION / VERIFICATION WELLS
(For back up field data collection in the event of power outage or other data transmission loss from automated gauges – see "*Instructions*")

USEPA Site #1150155136 – Macon County Archer Daniels Midland – Corn Processing Carbon Sequestration Injection and Verification Wells	Permit No. Well No. UIC Log #

ADM Supervisor: ______________________________
Readings Taken by: Name: ______________________________
Phone: ______________________________

Check Box(es) Above Failed Instrument(s) ➔						
DATE	**TIME**	**Injection Wellhead Pressure** PIT-009 (psig)	**Injection Annulus Pressure** PIT-014 (psig)	**Verification Tubing Pressure** Westbay (psig)	**Verification Annulus Pressure** Westbay (psig)	**INITIALS**

INSTRUCTIONS – *Within 30 minutes of a communication loss, manual readings of the pressure in the tubing and annulus of both wells will be taken and recorded, and continued every 4 hours thereafter until communication is restored.*

Figure 10 - 2 Example Field Log Form for Manual Verification Well Gauge Readings

10.2 CONTINGENCY EQUIPMENT AND PLAN FOR INJECTION WELL CCS#1

This contingency plan provides expanded detail into situations that may require system shutdown. It also details how the control system is designed to facilitate operational monitoring and equipment shutdown.

10.2.1 Injection Well Shutdown

With the exception of routine or scheduled maintenance and certain system testing procedures, injection will be shut down under the following conditions:

- Wellhead injection pressure (PIT-009) reaches the automatic shutdown pressure of 1,950 psig. Fracture gradient was determined to be 0.715 psi per foot, so for the mid-perforation depth of 7,025 feet the fracturing pressure would be 5,023 psig. Using a CO_2 density of 47.31 lbs/cu. ft with a hydrostatic gradient of 0.3285 psi/ft during injection, a wellhead pressure of 2,714 psig would be required to fracture the formation with CO_2at this density. The compression system has been designed and constructed for surface injection pressures between 1,057 psig and 1,950 psig. The pipeline system has been designed and constructed for working pressure up to 2,000 psig, based on the ASME code mandated stress analysis of the pipeline components. Therefore, the surface equipment is the pressure limitation and not formation fracturing pressure.

- Pressure readings fall below the limits as defined by the Permit (1,070 psi near bottom of the well) either measured downhole or calculated by a surface pressure gauge (PIT-009).

- Maximum Injection Rate (FIT-006) exceeds the limits as defined by the Permit (1,200 tonnes/day) for longer than 8 hours.

- Downhole temperature varies outside the permitted range (60 - 210°F); may be calculated from surface temperature sensor (TIT-009).

- Failure to maintain at least 400 psig pressure on the tubing/casing annulus (measured at the surface, PIT-014) for a period longer than 24 hours.

- Failure to maintain a pressure within the annular space greater than the pressure of the injection zone over the depth interval between the packer and the confining layer for a period longer than 24 hours. Pressures to be calculated from surface gauge readings (PIT-009, PIT-014) and/or downhole gauges.

- There is reason to suspect that the injection well or cap rock integrity has been compromised via one or more of the following:

  a. Mechanical integrity testing indicates CO_2 migration above the cap rock. These tests include annular pressure tests, time lapse sigma logging and temperature surveys.

  b. Shallow groundwater compliance monitoring shows a statistically significant change in groundwater quality that is a direct result of CO_2 injection.

The limits listed above apply to the injection of CO_2 except during startup, testing and shutdown periods.

If a shutdown occurs by any of the control devices, then an immediate investigation will be conducted. The condition will be rectified or faulty component repaired and system will be restarted.

If the system is shutdown due to sub-surface or wellbore related issues, an investigation will be undertaken as to the cause of the event that initiated the shutdown, as per the EERP.

10.2.2 Surface System

Shutdown systems will be in place in order to meet permit-required shutdowns for surface injection temperature range excursions, for exceeding maximum injection pressures orflow rates, or failure to maintain annulus pressure. Stopping CO_2 flow to the wellhead, venting the CO_2, and the shutdown of compression equipment (if necessary) will be controlled by a monitoring system that takes into account specific requirements of the permit, e.g., a high pressure condition in the well. Table 10-2 below lists the surface injection operating parameters

Table 10 - 2 Surface injection operating parameters.

Surface Injection Parameter	Operating Range
CO_2 Injection Flow Rate	250 to 1,100 metric tons/day
Flow Rate Variation	+/- 10% of flow rate set point
Wellhead Inlet Pressure	< 1,950 psig
Annulus pressure at surface	> 400 psig

The Surface System for the Midwest Geological Sequestration Consortium Phase III project includes compression and dehydration equipment that takes a water-saturated CO_2 gas stream from an ethanol plant wet scrubber discharge at approximately 90 °F and 0.5 psig and compresses the CO_2 to pressures up to 2,000 psig. Gas is also dehydrated to typical CO_2 pipeline concentrations of ≤ 30 lb/MMSCF or 630 ppmv at an intermediate step in the compression process. The compression and dehydration equipment is located east of the ethanol fermenters in the Corn Processing Facility. Compressed, dehydrated CO_2 at rates up to 1100 metric tons/ day (21 MMSCFD) can be delivered to the pipeline at pressures ranging from 1400 to 2000 psig and temperatures ranging from approximately 80 to 120 °F. CO_2 travels through approximately 6400 feet of 6-inch diameter Schedule 40 pipe from the Surface System to the injection well. Instrumentation to measure and record key operating pressures, temperatures, flow rates and other process parameters is also included with the Surface System.

The Process Control Strategy Diagrams (PCSDs) for the Surface System are shown in Figures 4-2 and 4-3.

The equipment consists of a single 1250 hp centrifugal booster blower that raises pressure to approximately 17 psig, followed by two parallel 3250 hp 4-stage reciprocating compressors that boost the pressure to 1400 psig, a dehydration unit, and a 200 hp multistage centrifugal pump that boosts the pressure to up to 2000 psig. Triethylene glycol dehydration is performed between the third and fourth stages of the reciprocating compressors, where water content in the CO_2 is at a minimum due to previous compression and cooling steps. Shell and tube heat exchangers using cooling water remove the heat of compression following each compression step, except after the multistage centrifugal pump which causes minimal temperature rise (10 to 15 °F). Additional description of the Surface System is provided in the following paragraphs.

The Process Control Strategy Diagram (PCSD) in Figure 4-2 depicts the key control loops and instrumentation for the compression train. The compression train receives the relatively low pressure CO_2 stream from an existing primary water scrubber overhead stream. The gas enters the inlet separator, TK-101, where any free water carry-over from the scrubber is allowed to drop out. The water level in TK-101 is controlled by a level switch (LSH-101). The pressure (PTX-101A) and temperature (TIT-101A) of the TK-101 overhead stream are measured before the stream enters the blower, BL-101, where the CO_2 pressure is increased by approximately 16 psi. The blower outlet temperature and pressure are monitored by TIT-101B and PTX-101B. The gas stream is then cooled by a shell and tube gas cooler, HE-101. The outlet gas temperature is measured by TIT-102A and controlled at a set point of 95 °F via TCX-102A which is located on the heat exchanger cooling water outlet. The gas pressure downstream of the HE-101 is measured by PTX-102. The outlet cooling water temperature of HE-101 is measured by TIT-005.

The CO_2 stream then enters the blower after cooler separator, TK-102, where any condensed liquid is allowed to drop out. The water inventory in TK-102 will be controlled by a level controller (LC-102). The gas stream is monitored for the presence of oxygen by an online oxygen analyzer ARX-001. A high oxygen reading may indicate an air leak into the system and that will require action from the operations staff. The overhead stream from the blower after cooler separator is split and enters the suction of two parallel 4 stage reciprocating compressors, VC-201 and VC-301. The suction pressure to the reciprocating compressors is controlled by PIC-102 which is located downstream of the TK-102 and upstream of the reciprocating compressors.

Each compression stage has a suction scrubber to remove any liquids, a suction pulsation bottle, compression cylinder(s), a discharge pulsation bottle, and cooler. Compressed CO_2 from the 3^{rd} stage of reciprocating compressors is cooled and then combines and enters the dehydration unit inlet separator where condensed liquids disengage from the vapor stream. The “wet” CO_2 stream then enters the bottom of the contactor where it is contacted counter currently with the lean (low water content) glycol that enters at the top of the contactor. The dry CO_2 exiting the top of the contactor is cooled in a gas/glycol exchanger before splitting and returning to the 4^{th} stage compressor suction scrubbers. The Process Control Strategy Diagram (PCSD) in Figure 4-3 depicts the triethylene glycol dehydration system including the inlet separator, the contactor, and the equipment on the regeneration skid that heats the water rich glycol to approximately 400 ^{o}F in order to boil water out of the glycol so that the regenerated, lean glycol can be returned to the contactor and reused to dry more CO_2.

The pressure of the combined reciprocating compressor discharge is measured by PIT-005 and the flow rate is measured by FIT-005. The pressure is controlled at a set point of up to 1400 psig by PIC-005 which allows excess compressed CO_2 to flow back to the process vent header if the injection rate to the wellhead is reduced. The temperature of this vent stream is monitored by TIT-004 and is associated with a low header temperature alarm.

Temperature control loops for each of the inter-stage shell and tube coolers (three for each compressor) as well as the temperature control for the final after cooler will control the outlet CO_2 temperature at a set point of 95 °F via a temperature control output signal to a flow control valve on the cooling water outlet of each exchanger. The CO_2 pressure and temperature after the final cooler outlet is measured using PIT-006 and TIT-006.

CO_2 flow to the wellhead is monitored by flow indicating transmitter FIT-006 and is controlled by flow controller FIC-006 in one of two ways, depending on if the multistage centrifugal pump is or is not used. If the wellhead injection pressure, as indicated by PIT-009 is 1400 psig or less, the pump will not be used and FIC-006 will control flow via flow control valve FCV-341. If the wellhead injection pressure is greater than 1400 psig, then the pump will be used and FIC-006 will control flow via the variable frequency drive (VFD) on the multistage centrifugal pump. FIT-006 measures the injection rate to the well in both operating modes.

CO_2 Flow Control by Flow Control Valve FCV-341

If the pump is not in use, flow is controlled by flow control valve FCV-341, XV-003 (multistage pump bypass valve) is opened and valves XV-32 and XV-33 are closed in order to isolate the pump. If the flow rate set point to the wellhead is lowered, FCV-341 throttles to reduce the flow. This restriction in the line will cause the pressure at pressure indicating transmitter PIT-005 to increase. Pressure controller PIC-005 will then open pressure control valve PV-005 to control the pressure at set point by allowing more CO_2 to flow to the process vent header.

CO_2 Flow Control by Pump VFD

If the multistage centrifugal pump PU-404 is required to meet the surface injection pressure necessary to achieve the desired CO_2 injection rate, CO_2 flow will be controlled by changing the pump speed. If the flow rate set point is increased, the variable frequency drive (VFD) on the pump motor will increase the pump speed and thus increase the CO_2 flow rate through the pump and to the injection well. In this scenario, the pump bypass valve XV-003 is closed and valves XV-32 and XV-33 at the multistage centrifugal pump inlet and outlet, respectively, are both open. When the pump is running, FCV-341 and PCV-014 work together as back pressure control valves downstream of the multistage pump to provide back pressure required for some wellhead pressure and flow combinations in the operating envelope of injection flow rates ranging from 250 to 1,100 metric tons / day and surface pressures ranging from 1,400 to 2,000 psig.

The water content of dehydrated gas stream is measured between the dehydration unit contactor outlet and the inlet of the fourth stage of the reciprocating compressor via ARX-006. A water content measurement indicating greater than 10 lb/MMSCF (211 ppmv) will result in a process alarm. Operators will be required to investigate and troubleshoot the cause of the alarm.

An automated block valve XV-347 is part of the control scheme for preventing flow of the CO_2 to the well head during emergency shutdowns. Final surface temperature (TIT-009) and pressure (PIT-009) will measured at the well head inlet before the compressed CO_2 enters the well head. A check valve is also provided near the wellhead inlet to prevent backflow from the well into the pipeline.

Automated systems will be in place in order to meet permit required shutdowns for exceeding maximum injection pressures. Stopping CO_2 flow to the wellhead, venting the CO_2 to the existing plant vent, and the shutdown of compression equipment will be controlled by the ADM monitoring system that takes into account specific requirements of the permit, e.g., a high pressure condition at the wellhead.

The CO_2 compression, transmission, and injection system will have a robust monitoring and alarming structure to identify any foreseeable malfunction, automatically respond where appropriate, and notify ADM staff as needed. More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate have continuous electronic monitoring with signals transmitted back to a master control system. A list of these instruments can be found in the Surface Facilities Instrumentation Summary in Appendix B which lists the instrument description/location, tag number, type of instrument, brand/model number, service, compatibility and operating range information. The table also lists whether the instrument activates a shutdown of surface equipment. Real time monitoring for water and oxygen content is also included in the plant design. The recording devices, sensors and gauges used to verify compliance with the UIC permit conditions meet or exceed the maximum operating range by 20%. See Appendix B - Surface Facilities Instrumentation Summary for a complete instrumentation list and details. A summary of the instrumentation accuracy can be found in Table 10-3.

Table 10 - 3 Instrument accuracy as reported by equipment suppliers.

Instrument Type	Brand	Accuracy Description
Pressure	Durkin (ABB)	± 0.075% base accuracy
Pressure	Rosemount	± 0.04% reference accuracy resulting in ± 0.15% total operating performance; Stability (5-yr): ± 0.125%
Temperature	ICT	Transmitter: ± 0.1% of span
Temperature	Rosemount	± 0.02% of span D/A Accuracy, RTD Stability: ± 0.1% or 0.1 °C, whichever is greater for 24 months
Flow	SCADASense	Differential & Absolute Pressure: ± 0.05% of span (for spans between 10% and 90% of Upper Range Limit (URL); Digital Output (spans < 10% URL): ± (0.005) x (URL/Span)% of Span; Long Term Drift Stability: ± 0.05% of URL per year over 5 years; Temperature: ± 0.15°C (±0.27 °F) (not including RTD uncertainties)
Moisture	AMETEK	Accuracy (typical): 2% of reading or ± 4 ppmv whichever is greater (Lower range option: 2% of reading or ± 1 ppmv); Repeatability (typical): 2% of reading or ± 4 ppmv, whichever is greater (Lower range option: 2% of reading or ± 1 ppmv)
Oxygen	Advanced Instruments or Advance Micro Instruments	Accuracy : ± 1% of Full Scale Range

ADM supervisors and operators have the capability to monitor the status of the entire system in two locations: the compression control room (near the compressors), and the main Alcohol Department control room. Should one of the parameters go into an alarm status, the control system logic will automatically make the necessary changes, including shutting down the entire compression system and isolating it from the pipeline leading to the injection well if warranted. At the same time, audible and visual alarms activate in both the compression control room and the main Alcohol Department control room. Alcohol Department supervision personnel will respond to the alarms, identify the problem, and dispatch the necessary resources to address the problem. A loss of power to the compression system necessarily shuts down surface compression and injection. Automatic shutdown valve XV-347 (fail closed) on the transmission pipeline automatically shuts in the pipeline due to loss of power. A check valve on the wellhead wing prevents any backward flow of CO_2 out of the wellhead.

A Hazard and Operability Study (HAZOP) was conducted in September 2009 for the design of the CO_2 compression and dehydration portions of the Surface Facilities. The process nodes evaluated during the HAZOP were Blower, Reciprocating Compression Stages 1, 2, 3 and 4, and the Dehydration Unit CO_2 flow, and Dehydration liquids. A second HAZOP review was held in May 2010 to review the multistage centrifugal pump, pipeline, and wellhead systems. Engineering and Administrative Controls were specified for each of the consequences identified during the HAZOP.

Surface Injection Equipment

Two full flow relief valves (PRV-001 and PRV-002) are installed immediately downstream of the multistage centrifugal pump and on the main pipeline downstream of the pump, respectively, in order to protect piping and equipment in the event of accidental closure of either an automated valve or a manual valve downstream of the compression system. PRV-001 and PRV-002 each have a pressure relieving set point of 2,000 psig. According to the manufacturer, the relief valves have leak-free system operation at pressures close to the PRV set pressure, consistently relieve within code tolerances, reseat bubble tight after short and stable blowdown, and operate through many relief cycles without maintenance. There are also two spring-operated thermal relief valves installed along the pipeline (TRV-001 and TRV-002). The purpose of these valves is to relieve small amounts of gas due to an increase in pressure from thermal expansion that could result if the pipeline is full and isolated for maintenance of either compression equipment or the wellhead. Closure of these valves is assisted by the development of a controlled backpressure in the spring chamber.

Wellbore and Wellhead:

The plan for the injection well includes but is not limited to the following:

1. A single master and single wing Xmas tree assembly with a swab valve above flow tee. Wing valve will have a check valve installed directly upstream of the valve to prevent backflow into the pipeline.

2. All annuli will have pressure gauges and sensors to detect any abnormal pressure spikes. See Appendix B - Surface Facilities Instrumentation Summary for gauge details.

3. Injection pressure at the wellhead will be a constantly recorded as well as at the discharge side of the compressor(s). Annulus pressure will be monitored and recorded. See Appendix B – Surface Facilities Instrumentation Summary for gauge details.

4. Along with continuous, real time recording and automatic shut-down systems, a daily field visit to the compression and dehydration facilities will be performed by the facility

operator to ensure integrity of the surface systems and apparent functionality of all mechanical equipment seven days a week

5. All Xmas tree equipment is rated to at least 3,000 psig working pressure, plus the Xmas tree assembly (upper valve assembly) is constructed of stainless steel and/or chrome.

6. Normal operating pressure at the wellhead will be 1,900 psig or less. Alarms will be set at 1,925 psig and automatic shutdown will occur at 1,950 psig. Maximum surface injection pressure at the wellhead will be 1,950 psig.

10.3 CONTINGENCY EQUIPMENT AND PLAN FOR THE VERIFICATION WELL

If necessary, the tubing string can be retrieved from the well. While this may not be the first course of action in response to information from the integrity monitoring measurements, this option is available if required. The monitoring well(s) will be remediated under the following conditions:

1) Abnormal annular pressure readings are observed.

If there are pressures measuring 300 psi over static levels in the well annulus, an alarm will be triggered. If the pressure does not bleed down, further investigation as to the cause will be employed and remediation planned. The pressure of 300 psi was chosen because this pressure is within the tubing operating limits and is high enough that it would be well beyond any pressure increases due to temperature changes or minor pressure anomalies, but not high enough to cause damage to the wellbore or a loss of wellbore integrity.

2) Abnormal pressure / water levels are observed inside the tubing

If there are pressures measured 500 psi over static levels inside the tubing, an alarm will be triggered. ADM or ADM contractors will check for a possible tubing leak. Further investigation will be conducted regarding the cause of the abnormal pressure reading, and remediation will be planned if warranted by the situation.

3) Abnormal pressure readings in the downhole blank QA zone.

On-going fluid pressure measurements from the QA zone during and after CO_2 injection will be compared to background data trends and the persistent presence of a pressure difference (corrected for depth and fluid density) between the QA Zone and the adjacent perforated zone. If an unexpected decrease of corrected pressure difference is identified, a packer leak will be suspected. Further investigation will be conducted as to the cause of the abnormal pressure readings. Remediation will occur if the investigation points to a failure which would allow upward fluid migration past the upper boundary of the Eau Claire seal.

4) Suspect that the well integrity has been compromised.

5) Surface equipment has been damaged.

If any of above should occur, steps will be taken to identify and correct any equipment deficiencies. Many interventions can be carried out using the Westbay wireline system to affect repairs and re-establish well bore integrity. If all of these interventions were unsuccessful, plans would be made to remove the Westbay monitor system from the well. If required, retrieval of the tubing string would be done with BOPs in place according to the following summarized procedure:

1) Secure well until a workover rig and support equipment can be mobilized. Notify IEPA and US EPA of planned workover.

2) Rig up workover rig with pump and tank. Bleed down any pressure. Fill both tubing and annulus with kill weight fluid.

3) Go in hole with Westbay wireline assembly and release top packer. Open pumping port andattempt to circulate fluid at very low rate. Close pumping port and proceed to next packer.

4) When all packers are released and relaxed, pull plug (if a plug was placed in bottom of Westbay string) and attempt to slowly circulate the well with kill weight fluid.

5) Prepare to remove tubing string from the well while carefully keeping the hole full of kill weight brine. Pull tubing slowly as to not over-pull the designed strength of the tubing.

6) Remove tubing from the well and examine to identify the cause of the anomalous pressure. Upon removal, a decision will be made as to whether to repair and replace or to plug and abandon the well.

11. FINANCIAL ASSURANCE DOCUMENTATION

Applicant will provide the permitting agency with the required financial assurance documentation after the appropriate costs are proposed and validated by both parties. The Applicant will provide financial assurance in a form approved by the permitting agency for AoR corrective action, injection well plugging, post-injection site care, and emergency and remedial response.

The financial assurance plan will be submitted before or with the well completion report.